BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
DOCKET NO. 2019-182-E

IN RE:	)	
	)	**PROPOSED ORDER OF VOTE**
South Carolina Energy Freedom Act (H.3659) Proceeding Initiated Pursuant to S.C. Code Ann. Section 58-40-20(C): Generic Docket to (1) Investigate and Determine the Costs and Benefits of the Current Net Energy Metering Program and (2) Establish a Methodology for Calculating the Value of the Energy Produced by Customer-Generators	)	**SOLAR, SOUTH CAROLINA COASTAL CONSERVATION LEAGUE, SOUTHERN ALLIANCE FOR CLEAN ENERGY, UPSTATE FOREVER, NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, AND SOLAR ENERGY INDUSTRIES ASSOCIATION**

January 21, 2021

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I. INTRODUCTION

Continuing the Commission's implementation of the South Carolina Energy Freedom Act ("Act 62") (enacted by General Assembly in H.3659 (2019)), this Order adopts a new analytical framework to evaluate customer-generator programs, including the existing net energy metering ("NEM") program and pending future Act 62 solar choice metering programs. The purpose of this generic docket is to "investigate and determine the costs and benefits of the current net energy metering program" and to "establish a methodology for calculating the value of the energy produced by customer-generators." S.C. Code Ann. § 58-40-20(C). The Commission does not address the structure or merits of any solar choice metering tariff proposals in this order, but defers consideration of those issues to ongoing dockets established specifically for that purpose. Further, the Commission does not make specific findings of costs and benefits for the electrical utilities at this time. Rather, this Order solely establishes the analytical framework for investigating and determining the costs and benefits of customer-generator programs. The Commission will revisit the determination required by law after reviewing the evidence produced in the separate solar choice metering proceedings and determining whether any further proceedings are required to fulfill the Commission's duty under Act 62.

The Commission intends the analytical framework to be iterative and flexible, evolving over time to adjust to circumstances, innovation, and technological advances. Under Act 62, the Commission is required to evaluate the costs and benefits of the existing NEM program using an enumerated list of factors. S.C. Code Ann. § 58-40-20(F)(2). Specifically, the Commission must consider:

(1) the aggregate impact of customer-generators on the electrical utility's long-run marginal costs of generation, distribution, and transmission;

(2) the cost of service implications of customer-generators on other customers within the same class, including an evaluation of whether customer-generators provide an adequate rate of return to the electrical utility compared to the otherwise applicable rate class when, for analytical purposes only, examined as a separate class within a cost of service study;

(3) the value of distributed energy resource generation according to the methodology approved by the commission in Commission Order No. 2015-194;

(4) the direct and indirect economic impact of the net energy metering program to the State; and

(5) any other information the commission deems relevant.

S.C. Code Ann. § 58-40-20(D). The statute provides a mix of prescriptive analytical categories the Commission must consider alongside discretion for the Commission to exercise within its otherwise applicable jurisdiction and authority. Notably, Act 62 does not establish a date certain by which this evaluation of the existing program must conclude.

The Commission, however, intends to use this list of cost-benefit factors and analyses (*i.e.*, the components of the analytical framework adopted here) to fulfill the legislative intent of Act 62 in adopting new solar choice metering tariffs, which are required to be approved and in effect by June 1, 2021.

In adopting a successor policy to NEM, the General Assembly, specifically, has asked the Commission to balance three central objectives to:

(1) build upon the successful deployment of solar generating capacity through Act 236 of 2014 to continue enabling market-driven, private investment in distributed energy resources across the State by reducing regulatory and administrative burdens to customer installation and utilization of onsite distributed energy resources;

(2) avoid disruption to the growing market for customer-scale distributed energy resources; and

(3) require the commission to establish solar choice metering requirements that fairly allocate costs and benefits to eliminate any cost shift or subsidization associated with net metering to the greatest extent practicable.

S.C. Code Ann. § 58-40-20(A). To accomplish these goals the Commission must use the required tools provided by Act 62. The Commission finds it necessary to proceed sequentially in developing the analytical tools to fairly evaluate customer-generator programs and then to apply this Act 62 analytical framework to establish the successor solar choice metering tariff in a manner that achieves legislative intent. The Commission finds it reasonable to infer that the General Assembly intends for it to complete and approve the analytical framework prior to the approval of solar choice metering tariffs by May 31, 2021.

As discussed more fully below, it is reasonable to apply the analytical framework in a flexible manner to account for the fact that parties—by no fault of their own—were required to proceed with solar choice metering proposals without guidance regarding any additional evidence we would require to populate the analytical framework for customer-generator programs. Accordingly, as this is an iterative framework, the Commission will address each electrical utility's case individually and assess whether there is sufficient evidence in those proceedings to satisfy the mandatory elements of evaluation of customer-generator programs that are prescribed by Act 62. The Commission retains significant discretion to approve interim measures to offer to customer-generators while resolving any serious evidentiary deficiencies.

A. Background of Net Energy Metering in South Carolina

This Commission first considered net metering in response to an Office of Regulatory Staff ("ORS") petition for the Commission to consider implementing various voluntary provisions of Section 1251 of the Energy Policy Act of 2005 ("EPAct"). The Commission opted to adopt net metering on a limited basis through Order No. 2007-618 issued August 30, 2007, which required South Carolina Electric & Gas Company ("SCE&G") (now Dominion Energy South Carolina or "DESC"), Carolina Power & Light Company (now Duke Energy Progress, LLC or "DEP"), and Duke Energy Carolinas ("DEC") to file net metering tariffs. Order No. 2008-416 issued June 24, 2008 required a review of the net metering programs in approximately twelve months so the Commission could consider whether any changes were warranted at that time.

In Order No. 2009-552 issued August 6, 2009, the Commission undertook a review of the experimental net metering tariffs adopted in compliance with federal EPAct of the various electrical utilities and approved a settlement that, among other things: (1) standardized the structure of the NEM program for statewide uniformity; (2) allowed a full retail credit (one-to-one kWh offset) under the flat rate for excess energy credits (as opposed to a mandatory time-of-use rate with a demand component); (3) eliminated standby charges; (4) allowed "renewable energy generators" to retain the rights to Renewable Energy Credits ("RECs"), except for those associated with net excess generation; and (5) provided for review of the program in four years.

In 2014, the General Assembly codified the NEM program by adding a new Chapter 40 to Title 58 as part of the South Carolina Distributed Energy Resource Act, S.1189 ("Act 236"). Act 236 capped participation in NEM at "two percent of the previous five-year average of the electrical utility's South Carolina retail peak demand" (S.C. Code

Ann. § 58-40-20(B) (2014)) and only came into legal operation if a utility had an approved Distributed Energy Resource ("DER") Program.[1]

The Commission then approved a settlement in Order 2015-194 establishing the Act 236 NEM program, which included a procedure for annually calculating the value of DERs (the "NEM Methodology") and for collecting the so-called NEM DER Incentive, which was calculated by subtracting the value of DER from the full retail rate that was offset by each kWh of generation for customer-generators. Under the NEM Methodology, the total value of DERs is determined by summing eleven different cost and benefit components; Order No. 2015-194 defines and provides a calculation methodology for each of those components (NEM Methodology table included as Attachment A). The NEM Settlement, among other things, also established that full retail net energy metering (i.e., the one-to-one kWh crediting rate) would be offered on a first-come basis through the NEM Settlement effective period (i.e., until January 1, 2021) or until statutory limits on program participation under Act 236 were reached. The NEM Settlement provided that customer-generators applying and receiving service pursuant to the NEM Settlement "shall have the right to remain on that rate, according to the terms and conditions specified in this Settlement Agreement through December 31, 2025."

On May 16, Governor McMaster signed the South Carolina Energy Freedom Act ("Act 62"). Act 62 modified much of Chapter 40 (Net Energy Metering), Title 58—first established by Act 236. Act 62 extends the terms and conditions of the Act 236 NEM settlement (approved by Order No. 2015-194) for customer-generators that apply for NEM service after the effective date of the Act and before June 1, 2021 ("Interim

[1] The DEP program was approved by Order 2015-514 (July 15, 2015); DEC's program was approved by Order No. 2015-515 (July 15, 2015); and SCE&G program was approved by Order No. 2015-512 (July 15, 2015).

Customer-Generators"). Act 62 requires the Commission to establish Solar Choice Metering tariffs to be a successor to Act 236's Chapter 40 NEM tariffs and to "(1) investigate and determine the costs and benefits of the current net energy metering program; and (2) establish a methodology for calculating the value of the energy produced by customer-generators." S.C. Code Ann. § 58-40-20(C)(1).

B. Commission Jurisdiction and Authority Over Net Energy Metering and Customer-Generator Programs

Net energy metering is a retail practice that involves billing a customer for their net electrical consumption. Section 58-40-10(E) defines "net energy metering" as involving "the difference between the electrical energy supplied to a customer-generator by an electrical utility and the electrical energy supplied by the customer-generator to the electricity provider over the applicable billing period." The Commission establishes the schedule of rates, fees, credits, and charges for the applicable rate to which the NEM billing practice applies, and Act 236 defined the "applicable billing period" over which these exports and imports of electricity are netted. Under the Act 236 form of NEM, these one-to-one retail NEM credits were applied across the annual billing period as set by statute, with any excess remaining at the end of the annual billing period compensated to the customer-generator at the electrical utility's avoided cost.[2] Prior to that, the Commission acted under its authority pursuant to the EPA Act to consider and adopt NEM. The Commission subsequently used our retail jurisdiction to extend the billing period to provide for one-to-one full retail offset over an annual period.[3]

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[2] Prior Section 58-40-20(D)(4) provided that "Annually, the utility shall pay the customer-generator for any accrued net excess generation at the utility's avoided cost for qualified facilities, zeroing-out the customer-generator's account of net excess kWh credits." Section 58-40-20(D)(4) (2014).

[3] Commission Order No. 2009-552.

The payment for excess credits at the end of the billing period, on the other hand, involves the payment or crediting of those excess kWh credits at the utility's avoided cost, a wholesale rate. Ordinarily, the Federal Energy Regulatory Commission ("FERC") has exclusive jurisdiction over "the sale of electric energy at wholesale in interstate commerce," (16 U.S.C. § 824(b)(1)) with the exception of the establishment of wholesale rates for purchases by utilities from Qualifying Facilities ("QFs") under the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). 16 U.S.C. § 824a-3 *et seq.* FERC has consistently upheld state jurisdiction over the retail practice of establishing the NEM billing mechanism, subject to the constraints of PURPA in establishing compensation for net excess generation. *See, e.g., Sun Edison LLC,* 129 F.E.R.C. ¶ 61,146 (2009); *MidAmerican Energy*, 94 F.E.R.C. ¶ 61,340 (2001). As FERC observed:

> The Commission has explained that net metering is a method of measuring sales of electric energy. Where there is no net sale over the billing period, the Commission has not viewed its jurisdiction as being implicated; that is, the Commission does not assert jurisdiction when the end-use customer that is also the owner of the generator receives a credit against its retail power purchases from the selling utility. Only if the end-use customer participating in the net metering program produces more energy than it needs over the applicable billing period, and thus is considered to have made a net sale of energy to a utility over the applicable billing period, has the Commission asserted jurisdiction.

Sun Edison LLC, 129 F.E.R.C. ¶ 61,146, 61620.

Accordingly, the Commission's jurisdiction over NEM is rooted in the exclusive jurisdiction that states retain over retail rates, but is subject to the constraints of PURPA in establishing an avoided cost rate for any net excess generation that remains at the end of the "applicable billing period." *Id.* The Commission does not here establish an applicable billing period for the successor solar choice tariffs in this proceeding, but it does recognize that the extent of our discretion and jurisdiction should inform how we evaluate and establish a successor solar choice metering tariff. Indeed, subsections (2) and (3) of Section 58-40-20(F) provide that the Commission is to consider "calculating the solar choice metering measurement that is just and reasonable in light of the costs and benefits of the solar choice metering program…" and determine "the appropriate billing mechanism and energy measurement interval" as part of its consideration of future solar choice metering tariffs. Subsection 58-40-20(G)(2) requires us to "permit solar choice customer-generators to use customer-generated energy behind the meter without penalty." The Commission's duties in determining the applicable billing period (i.e. "appropriate billing mechanism and energy measurement interval") is grounded in the exercise of its retail jurisdiction. The analytical framework should provide information that is appropriate to inform the exercise of this jurisdiction and discretion, distinct from the Commission's obligations and constraints under federal law when establishing wholesale rates for QFs under the limited authority delegated to state regulatory authorities by PURPA.

The Commission acknowledges that it establishes a rate of compensation for net excess generation that remains at the end of the billing period or defined "energy measurement interval" pursuant to PURPA. The analytical framework adopted in this Order is appropriate for evaluating the NEM program and future customer-generator programs under our jurisdiction over retail rates and retail practices. This analytical framework is not intended to be precedential or to replace the existing methodologies approved for calculating the avoided cost paid by electrical utilities to QFs. Because the practice of netting does not involve the "sale" of electricity—as FERC has long held—the Commission evaluates customer-generator programs like NEM or successor solar choice metering according to standards appropriate to other retail programs, including energy efficiency and demand-side management. The Commission must engage in a balancing of interests and legislative objectives using its retail jurisdiction, which requires it to consider a range of long-run forward looking values that may or may not be well-suited to the evidentiary standards used to substantiate wholesale avoided cost rates pursuant to FERC PURPA regulations.

II. NOTICE AND INTERVENTION

This docket was opened on May 28, 2019 pursuant to Act 62's directive that the Commission determine the costs and benefits of the existing metering program and update the valuation of customer-generator produced electricity, as a precursor to establishing new solar choice metering tariffs to go into effect on June 1, 2021.

Alder Energy Systems, LLC ("Alder Energy systems"), North Carolina Sustainable Energy Association ("NCSEA"), Nucor Steel – South Carolina ("Nucor Steel"), the South Carolina Appleseed Legal Justice Center ("Justice Center"), South Carolina Department of Consumer Affairs, Solar Energy Industries Association ("SEIA") South Carolina Coastal Conservation League ("CCL"), Southern Alliance for Clean Energy ("SACE"), Upstate Forever, and Vote Solar intervened. The South Carolina Office of Regulatory Staff ("ORS") is automatically a party pursuant to S.C. Code Ann. § 58-4-10(B).

III. HEARING

The Commission convened a remote hearing via WebEx on this matter on November 17 through 19th, with the Honorable Justin T. Williams, Chairman, presiding.[4]

[4] On November 18-19, 2020, Vice Chair Florence P. Belser presided as chair while Chairman Williams was on leave.

DESC was represented by Matthew W. Gissendanner, Esquire. Duke Energy was represented by Heather Shirley Smith, Esquire, and J. Ashley Cooper, Esquire. The Justice Center was represented by Adam Protheroe, Esquire. Nucor Steel was represented by Robert R. Smith, II, Esquire. Vote Solar was represented by Thadeus B. Culley, Esquire, and Bess J. DuRant, Esquire. NCSEA was represented by Jeffrey W. Kuykendall, Esquire, and Peter Ledford, Esquire. SEIA was represented by Jeffrey W. Kuykendall, Esquire. CCL, SACE, and Upstate Forever were represented by Kate Lee Mixson, Esquire. Alder Energy Systems was represented by R. Taylor Speer, Esquire. ORS was represented by Jeffrey M. Nelson, Esquire, and Jenny R. Pittman, Esquire. In this Order, DESC, Duke Energy, the South Carolina Appleseed Legal Justice Center, Nucor Steel, Vote Solar, NCSEA, SEIA, CCL, SACE, Upstate Forever, and ORS are collectively referred to as the "Parties" or sometimes individually as a "Party."

Through their personal appearances, DESC presented the direct and responsive testimony of Mark C. Furtick, direct testimony of Scott Robinson, and direct and responsive testimony of Margot Everett. Through their personal appearances, Duke Energy presented the direct testimony of George V. Brown and Leigh C. Ford and the direct and rebuttal testimony of Julius A. Wright, Ph.D, Bradley Harris, and Lon Huber. Through their personal appearance, Vote Solar, CCL, SACE, Upstate Forever, SEIA, and NCSEA presented the direct and rebuttal testimony of R. Thomas Beach. Through their personal appearance, SEIA and NCSEA presented the direct and rebuttal testimony of Justin R. Barnes. Through their personal appearance, CCL, SACE, Upstate Forever, and Vote Solar presented the direct testimony of Frank L. Hefner, Ph.D. Through their personal appearance, Vote Solar presented the direct and responsive testimony of Odette

Mucha. Through their personal appearance, Alder Energy Systems presented the direct and rebuttal testimony of Donald R. Zimmerman. Through their personal appearances, ORS presented the direct testimony of Robert A. Lawyer, John C. Ruoff, Ph.D, and Brian K. Horii. The Justice Center and Nucor Steel did not present witnesses at the hearing.

IV. FINDINGS OF FACT

Based on the testimony and exhibits received into evidence at the hearing and the entire record of the proceedings, the Commission hereby makes the following findings of fact:

Analytical Framework for Evaluating Customer-Generator Programs Aggregate Marginal Benefits and Costs

1. The requirement of Act 62 to examine long-run benefits and costs of customer-generators in the aggregate to the utility's transmission, distribution, and generation components makes it appropriate to consider a range of values over the expected life of the typical customer-generator system within the analytical framework for analyzing the current NEM program and prospective solar choice metering programs.

2. Marginal costs are the change in the costs of providing electrical service due to a small change in demand, which are typically thought of as changes to variable cost. The Act 62 requirement to look at "long-run" marginal costs means that that the Commission should consider not just changes in variable costs, but also changes in "fixed" factors such as generation, transmission, and distribution assets because in the long-run these costs are also variable and only appear "fixed" from a short-term accounting perspective.

3. By their nature, long-run projections have uncertainty and reflect the risk of over- or underestimating a particular value over a long horizon for which there is

currently imperfect information. Considering a range of methodologically sound future estimates of long-run benefits and costs allows the Commission to utilize its discretion to give appropriate weight to this range of outcomes in its ultimate determination under the analytical framework.

4. Manufacturers' warranties on solar panels and regulatory treatment of solar assets in other jurisdictions support establishing a twenty-five-year expected useful life for solar photovoltaic ("PV") systems. Solar PV is expected to remain productive beyond that time, though total production will decline due to panel degradation.

5. All self-generation that is consumed by a customer-generator within the billing period is, from the system perspective, equivalent to energy efficiency or demand-side management measures as a decrement to system load.

<u>Cost of Service Analytical Tool</u>

6. The cost of service analysis required by Act 62 will provide evidence of the existence or extent of cross-subsidization between customer-generators and non-customer-generators in the same class within the snapshot of a single test year, but it is not conclusive of the existence of a cross subsidy over the long run (i.e., expected useful life of solar PV). The cost of service analysis will be helpful in fine-tuning solar choice metering rate design in future proceedings but will not itself be determinative.

7. Performing the Act 62 cost of service analysis requires consideration of a counter-factual circumstance, in which customer-generators within a class are separated out as a separate class for analytical purposes. This cost of service analysis aids the Commission in determining: (1) the cost to serve those customer-generators and (2) the relative rate of return received by the electrical utility in providing service to that theoretical class of customers.

8. Act 62 does not require the Commission to create a separate class of service for customer-generators and there is no reason to do so at this time.

9. Performing both embedded and marginal cost of service studies gives the Commission additional information to consider the impact of customer-generators on both historic and future utility costs.

10. Evaluating the theoretical customer-generator classes under the cost of service analytical factor requires load data, or a method consistent with an electrical utility's current load research, on a statistically significant sample of customer-generators. Where this is not currently possible, it is reasonable to estimate the hourly usage profile of a customer-generator using historic usage profiles and estimating the net hourly usage profile of these customers by applying the aggregate generation profile for that corresponding period recorded from all customer-generators with production meters owned and controlled by the electrical utility. The load of customer-generators should be evaluated within the cost of service analysis on the basis of net hourly consumption from the electric grid.

11. For purposes of the customer-generator cost of service study required by Act 62, a customer that is a net exporter of electricity during an hour has a negative net hourly consumption. That individual customer-generator's exports in that hour should be recorded as a negative number and not recorded as zero net consumption. This approach should also be taken to determine the aggregate hourly net load profile of all customer-generators within a class of service.

12. Other than the determination of the hourly net usage profile, it is reasonable to use the same Commission-approved cost of service allocators, including

methods of allocating costs to the theoretical customer-generators classes, on which effective rates are based at the time of the evaluation. It would be unreasonable to use non-Commission approved cost of service allocators that deviate from the methodology used to set rates in effect at the time of the evaluation. It is reasonable for a utility to use a test year more recent than that relied upon by the utility in its most recent rate case.

<u>Value of Distributed Energy Resources Methodology</u>

13. The existing cost-benefit categories for evaluation approved by Order 2015-194 are appropriate for determining the value of customer generation, subject to the requirement that all categories be populated with a value or that a proponent give a sufficient explanation for why it is not practical to determine a value for a particular category at that time.

14. While the categories of value of DERs approved in Order 2015-194 continue to be appropriate and well-accepted, updates to the methodology used to calculate values are required to be consistent with the Act 62 analytical framework and its requirement to include consideration of long-run marginal costs and benefits. To the extent this Order amends the calculation methodologies for the existing cost-benefit categories approved by Order 2015-194, it is appropriate to require that utilities use these updated methodologies in determining the distributed energy component of their overall fuel factor in annual fuel proceedings under S.C. Code §58-27-865(A) for purposes of determining the NEM DER Incentive cost recovery. It is reasonable for the Commission to reevaluate the NEM cost-benefit categories and their values on a biennial basis in this generic proceeding.

DER Value: Avoided Energy

15. There are temporal and seasonal variations in energy costs for electrical utilities that are not currently reflected in the existing valuation framework for DER. The avoided energy methodology follows the Commission's PURPA determinations and does not currently reflect the 25-year long-run marginal avoided energy cost required to be consistent with the requirements of Act 62.

DER Value: Avoided Capacity

16. Avoided capacity costs in the existing DER valuation framework do not currently reflect the twenty-five year expected life span of solar PV.

DER Value: Ancillary Services

17. Customer-generators do not currently provide ancillary services for compensation from electrical utilities. As commercially available technology expands the feasibility of customer DERs providing ancillary services and technical standards throughout the industry emerge, electrical utilities must investigate how they could create programs to leverage DER to provide ancillary services to populate this value category.

DER Value: Avoided Carbon Dioxide Emissions

18. The requirement in the existing DER valuation methodology that avoided carbon costs be limited to compliance costs is flawed and outdated. Act 62 embraces consideration of carbon pricing scenarios within the integrated resource planning context and it is appropriate to consider a twenty-five-year extension of those values for the purposes of this analytical framework.

DER Value: Avoided Fuel Hedge

19. It is appropriate to utilize both short and long-term scenarios to evaluate the fuel hedge value of customer-generator DERs within the analytical framework.

Because electrical utilities do not currently engage in twenty-five-year fuel hedging, it is appropriate to consider the current hedging practice as the short-term scenario. It is appropriate to quantify and acknowledge the risk of a twenty-five-year fuel hedge using fundamental forecasts as the outer, long-run boundary of this analysis.

DER Value: Avoided Transmission and Distribution Capacity

20. While not all utilities possess the granularity of data required to provide high-confidence quantification of avoided transmission and distribution value, there are techniques accepted across the utility industry for recognizing the avoided transmission and distribution values of DER.

21. The National Economic Research Associates regression method is a sufficient tool for quantifying the long-run impacts of the aggregate customer-generator fleet on avoided transmission and distribution costs.

DER Value: Avoided Line Losses

22. The best practice is to calculate avoided line losses on a marginal basis considering only daylight hours (when solar PV produces). Taking an average line loss value across all hours undervalues the specific line loss characteristics of customer-sited solar PV and should be adjusted.

DER Value: Utility Integration and Interconnection Costs

23. Utility integration costs are determined in the avoided cost proceeding, but should only be applied to exported power since behind the meter consumption is viewed the same as energy efficiency and class diversity smooths variations in net hourly customer load. Integration costs for customer-sited DER should focus more on any distribution-system related impacts, as most of the power produced by customer-

generators will be consumed by nearby load and will not face the same integration issues for the transmission system as a utility-scale solar facility, for example.

24. It is appropriate to require electrical utilities to begin to track the incremental interconnection costs associated with customer-generator interconnections that are not currently covered by the interconnection application fee to determine any negative or positive impact on revenue.

25. It is appropriate to treat reasonable and prudent administrative costs of facilitating customer-generators as a decrement to the value of DER, but the burden is on electrical utilities to demonstrate that they are taking measures to mitigate unnecessary expenses and are efficiently administering the customer-generator programs.

Economic Impacts of the Net Metering Program

26. The direct economic impacts of the NEM program are defined as the purchase of local services, labor, and goods from businesses in the residential solar sector.

27. The indirect economic impacts of the NEM program include: purchases of goods and services in South Carolina by businesses in the residential solar sector. Induced economic impacts (a subset of indirect impacts) of the NEM program are the impacts of purchases made possible by the wages paid to workers in the residential solar sector.

28. Act 62 requires the Commission to consider the direct and indirect economic impacts of NEM on the state. While this currently only includes the NEM program, this consideration will include solar choice metering as those programs are implemented.

29. The economic impacts of the net energy program are capable of quantification and calculation, but are to be used qualitatively in the Commission's consideration of the impact of NEM and successor programs on our state.

30. The Commission has the discretion in setting just and reasonable rates to consider the economic impact that specific proposals will have on the state economy, and Act 62 mandated consideration of these impacts in evaluating the NEM program and successor tariffs.

31. It is reasonable to rely on industry-provided job data to calculate economic impacts of that industry when the data comes from a reliable source and there is no evidence of error. The Solar Foundation's job data is based on reliable sources and no errors have been identified in the data, therefore it is appropriate to rely upon it for determining the economic impact of the solar industry, and residential solar sector, on South Carolina's economy.

32. IMPLAN, a modeling tool, is standard and widely accepted for evaluating the direct and indirect economic impacts of public policy. The Commission finds IMPLAN acceptable for purposes of determining the economic impact of NEM and any successor tariff on South Carolina.

33. The NEM program has contributed significant economic benefit to the state through jobs, tax revenue, and the indirect effects of customer investments in onsite solar generation.

34. In light of the economic benefits, the existing NEM program has provided net benefits to the state and has served the originally intended purpose of kick starting the solar market and giving customers more options.

<u>Cost-Effectiveness Tests</u>

35. Act 62 requires the Commission to balance the interests of all ratepayers, including NEM customer-generator participants and non-participants.

36. The Participant Cost Test is appropriate to consider whether the customer-generator program, including any associated incentives, provides a reasonable economic opportunity for customers to invest in and use DERs under a specific program (e.g., NEM or a future solar choice metering tariff).

37. The Utility Cost Test is appropriate as a primary test to determine whether any additional costs that result from customer-generator adoption of solar PV or DERs are offset by the direct benefits of the customer-generator program.

38. The Total Resource Cost test is appropriate as a secondary test to be used in conjunction with the Participant Cost Test and Utility Cost Test in evaluating the overall cost-effectiveness of NEM programs.

39. The Ratepayer Impact Measure test is inconsistent with the Act 62 Framework because it counts against and penalizes behind the meter consumption of onsite generation and takes a backward-looking view of utility costs that re-allocates sunk costs to customer-generators instead of considering incremental costs resulting from new customer-generators signing up under a particular program.

V. REVIEW OF EVIDENCE AND EVIDENTIARY CONCLUSIONS

A. Aggregate Impact of Customer-Generators on Long-Run Marginal Costs

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 1 THROUGH 5

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

Witness Beach, the joint witness of NCSEA, SEIA, Vote Solar, CCL, and SACE ("Joint Witness Beach"), testified that the challenge with determining the aggregate impact of customer-generators on the electrical utility's long-run marginal costs of generation, distribution, and transmission is "calculating long-run marginal costs for certain DER values over the full life of DER resources." (Tr. p. 290.15, ll. 6-9) Witness Beach stated that the expected life of solar PV is typically between 25 to 30 years and that such time frame is appropriate for determining long-run values. (Tr. p. 290.21, ll. 1-3) Witness Beach testified that it is standard for solar panels to come with a 25-year manufacturer's warranty. (Tr. p. 316, l.3 – 317, 1.12) Witness Beach's rebuttal noted that DESC Witness Everett's direct testimony did not analyze the costs and benefits of distributed solar resources over the full 25-year economic life of those systems. (Tr. p. 294.5, ll. 14-17)

DESC Witness Robinson testified that his analysis of payback period of the current NEM program assumed a "financial life of 20 years, with 0.5% annual degradation." (Tr. p. 93.7, ll. 18-20) DESC Witness Furtick conceded during cross examination that he performed sensitivity analyses for up to 30 years. (Tr. p.112 ll. 6-9) NCSEA and SEIA Witness Barnes cited a Maryland study that utilized a 25-year useful life time horizon (Tr. p. 327.17, ll. 2-5) and gave a range of expected useful life for solar PV of between 20 to 30 years. (Tr. p. 327.35, ll. 1-4)

Witness Beach stated that there are "longstanding and well-accepted" approaches to calculating long-run marginal costs within specific cost categories. (Tr. 290.22, ll. 1-5).

In rebuttal, Witness Beach described and applied techniques to calculate long-run avoided capacity costs for generation (Tr. p. 294.09, l. 8 – 294.10, l. 16), avoided transmission and distribution (Tr. p.294.12, l. 2 – 294.15, l. 2), and fuel hedge (Tr. p. 294.15, l. 4 – 294.17, l. 11), and estimated a value for each of those categories. (Tr. p. 294.18, l. 7) (Table 8).

DEC/DEP Witness Harris suggested that it is appropriate to view the long-run marginal costs of customer-generation differently based on whether the generation is consumed behind the meter or is "excess energy" exported to the grid. (Tr. p. 353.13, l. 23 – 353.14, l. 6) For behind the meter consumption, Witness Harris suggested that the impact is the same as if the customer had "reduced their consumption through an energy efficiency or demand-side management program" and should be evaluated in a similar manner. *Id.* For excess energy, Witness Harris stated that it should be evaluated in the same fashion as the Companies' avoided costs, as most recently approved in Docket Nos. 2019-185-E and 2019-186-E. *Id.*

ORS Witness Horii defined marginal costs as the "change in the costs of providing electrical service due to a small change in demand." (Tr. p. 576.9, ll. 1 – 2) Witness Horii noted that marginal costs are different than average costs, which reflect the costs of the output of all plants. (Tr. p. 576.9, ll. 4 – 5) Witness Horii suggested that the modifier "long-run" before marginal costs in statute "indicates that marginal cost should not just reflect changes in variable costs, but also consider changes in 'fixed' factors such as generation, transmission, and distribution assets." (Tr. p. 576.9, ll. 14 – 16)

<u>Commission Conclusions</u>

Act 62 establishes a new set of mandatory analytical tools to evaluate customer-generator programs which adds to and modifies existing methodology. With Order 2015-

194, the Commission approved a stipulated methodology for determining the value of DERs—or more precisely, the value of solar PV—and the record shows that the categories used to calculate these values remain largely accepted. This methodology has been used to establish the wholesale value of all generation from customer-generators in order to calculate the DER NEM Incentive, a cost recovery mechanism approved by Order 2015-194 as part of the compromise and settlement adopting the Act 236 full retail (one-to-one) NEM rate.

This method and approach does not necessarily include all of the relevant benefits of customer-generators (*e.g.*, cost of service allocation benefits) that Act 62 sets out for the Commission's consideration. Nor is the Commission currently bound by the fact that the electrical utilities have previously failed or declined to quantify values for every category in that methodology. Accordingly, it is appropriate to continue use of the valuation categories approved in Order 2015-194, with some modifications in this Order to calculation methodologies and new standards to apply when electrical utilities fail or refuse to calculate a particular value category. Any category or method that the Commission does not address or modify in this Order is carried forward.

The first major task the legislature put before the Commission was to expand the view of the existing DER valuation method to incorporate long-term costs and benefits from DERs. The Commission is required to consider "the aggregate impact of customer-generators on the electrical utility's long-run marginal cost of generation, distribution, and transmission…." S.C. Code Ann. § 58-40-20(D)(1). There is no real controversy over the well-accepted definition of marginal costs among parties, as incremental changes in variable costs due to a small change in demand. The Act 62 analytical framework for valuation of customer-generation is intended by the legislature to ensure that the Commission takes an appropriate long-run view of the benefits and costs of these customer-generators to an electrical utility's grid. Over the long-run, even costs the Commission has traditionally considered as "fixed" (*e.g.*, generation, distribution, and transmission) become variable.

As it concerns the length of time over which the analytical framework will view these costs and benefits, the Commission is mindful of the tensions identified by parties that the more distant in time the benefit or cost, the more uncertain the estimate. The Commission is persuaded, however, that it is appropriate to consider the cost-effectiveness of the asset at question as we would any other asset of the electrical utility; that is over the expected useful life of the asset. The Commission is mindful of the uncertainty embedded in future projections and will give appropriate weight based on the reliability and credibility of evidence putting forward future projects on the relevant analytical factors.

The record in this proceeding has revealed that a twenty-year useful life for solar PV is perhaps too conservative and underestimates the lifecycle benefits of solar PV. Evidence in the record reveals that it is standard for analyses of solar PV to consider 20-year and 30-year useful lives. The Commission finds it is reasonable to adopt the mid-range of these approaches and to utilize a 25-year expected useful or financial life for solar PV.

Additionally, as several witnesses observed, it is standard practice for the Commission to consider the cost-effectiveness of demand-side management and energy efficiency investments over the useful lives of those assets or programs. The Commission agrees with witnesses Beach and Harris that solar energy that is consumed by a customer over the course of a billing period to offset purchases from the utility looks like a reduction/decrement to load akin to energy efficiency, when viewed at a system perspective. Given that the analytical task at hand is to consider the cost-effectiveness of customer-generator programs over the expected useful life of the systems, the Commission adopts a 25-year horizon for considering these valuation categories and notes the distinction between customer-generator electricity that offsets retail kWh purchases from the electrical utility and those excess deliveries to the grid—as determined at the end of the billing period—which are treated as wholesale sales and compensated according to PURPA.

In particular, it is important to identify the difference between using this method to make a cost-effectiveness determination of a retail program, such as NEM, and the establishment of a wholesale rate under PURPA. The Commission acknowledges that PURPA grants states substantial discretion in determining the method of calculating avoided costs, but that we are constrained by federal statute and regulation in how we determine such a wholesale rate. This Commission's determination of PURPA avoided cost rates can be challenged before FERC and federal courts under the enforcement and judicial review provisions of Section 210 of PURPA. 16 U.S.C. § 824a-3(g),(h). By contrast, in evaluating state jurisdictional retail customer programs, the Commission has wide discretion to adopt a framework that reflects the legislature's intent of capturing the broad range of values that customer-generators may create. Put simply, the Paragraph D analytical framework in its totality—the tool by which the Commission will approve a successor solar choice metering tariff—asks to consider the customer-generator program and policy under an exercise of retail jurisdiction. The Commission establishes wholesale rates to compensate net excess generation – however excess generation is defined in a particular solar choice metering program – pursuant to PURPA.

In adopting a 25-year horizon for the analytical framework for valuing DER, the Commission notes that other elements of the Paragraph D framework take a more short-term look and offer information that is currently outside of the Order 2015-194 categories. For example, the subsection (D)(2) consideration of the "cost of service implications" of customer-generators is a novel analysis in South Carolina, that will take a look at customer-generators on utility revenues and costs within a single test-year. The Commission views these approaches as complimentary tools that provide very different information and have different applications in the exercise of Commission authority over NEM and successor solar choice metering tariffs.

B. Cost of Service Implications of Customer-Generators

1. Uses and limits of cost of service analysis of customer-generators

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NOS. 6 THROUGH 8

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

NCSEA and SEIA Witness Barnes testified that the usefulness of a cost of service study ("COSS") is relative to the overall analytical framework being used. Witness Barnes stated that a typical distributed generation ("DG") valuation method will take a long-run view of marginal benefits and costs, whereas a COSS represents a "snapshot in time of DG customer responsibility and payment for embedded costs." (Tr. p. 327.12, ll.

8 – 12) While a COSS provides useful information, Barnes suggested that it does not capture what is in the interests of ratepayers in the long term. As he explained, the scope of a COSS is narrower than the scope of a typical long-run DER evaluation because the "cost of service study focuses only on the past and only on costs reflected in the utility system." (Tr. p. 327.12, ll. 13 – 18) A consequence of this short-term look, Barnes suggested, is that a COSS tends to treat "some costs (*e.g.*, distribution investments) as fixed even though DG can contribute to longer-term avoidance of these types of costs." (Tr. p. 327.12, l. 21 – 327.13, l.3) Witness Barnes stated that it is common for jurisdictions to only perform a cost of service analysis after identifying the existence of a subsidy through the long-run evaluation of costs and benefits. According to Witness Barnes, the COSS is then helpful in pinpointing the degree of subsidy and in supporting future ratemaking treatment. (Tr. p. 327.13, ll. 9 – 21)

ORS Witness Horii echoed this distinction in his testimony, stating that "[u]nlike marginal cost studies that look at ***changes*** in costs, [COSS] look at how to divide a utility's total accounting costs among customer classes…." (Tr. p. 576.10, ll. 2 – 4)

Witness Barnes went on to explain that the benefits from DG (*i.e.*, NEM) customers in the COSS can manifest to other customers in the class in "the form of reduced allocation of costs to that class due to the presence of DG customers and how that compares to the amounts that DG customers avoid paying." (Tr. p. 327.12, ll. 18 -21) DEC/DEP Witness Harris' direct testimony stated that "adding solar reduced the transmission and production costs of the Companies in excess of 75%." (Tr. p. 353.11, ll. 2 – 3) At the hearing, DESC Witness Furtick was crossed on a table in his rebuttal testimony that illustrated that a typical solar generation profile might reduce a customer's contribution to daily peak by at least 40%, based on that limited single customer example. (Tr. p. 31, ll. 12 – 17) Witness Furtick conceded that he did not prepare the graph in question and was not certain of when the relative system peak occurred. (Tr. p. 30, ll. 12 – 13)

Joint Witness Beach stated that a cost of service analysis is required to justify separating customer-generators into their own rate class, as he explains that sufficient empirical evidence through a COSS would be needed to justify such distinct treatment. Witness Beach went on to state that "[i]t cannot be assumed that, after installing DER technology, customers will become significantly different than other customers in the class." (Tr. p. 290.29, ll. 13 – 14) Witness Beach further stated that breaking DER customers into separate classes could proliferate and cause confusion as more DER technologies emerge (*e.g.*, solar, storage, smart thermostats, and electric heat pumps) that all have unique impacts on a customer's load profile. (Tr. p. 290.29, ll. 17 – 19)

ORS Witness Horii provided direct testimony on how an embedded cost of service study that looks at customer-generators as their own class for analytical purposes can be used to determine whether a cost shift exists relative to customer-generators. Witness Horii stated that, after separating out customer-generators into a separate class (from regular non-solar customers), "the cost shift would be the difference between the costs allocated to these NEM solar and DR customers in the study compared to what those customers would pay under the otherwise applicable rate." (Tr. p. 576.12, ll. 7 – 9) Witness Horii stated that an embedded COSS approach to look at customer-generators as a separate class can examine existing actual rates and the impact of proposed rates, such as the Solar Choice tariffs. (Tr. p. 576.16, ll. 8 – 21)

Witness Harris's direct testimony provided a discussion of the cost of service analysis that he performed to analyze the existing NEM program. Witness Harris calculated the impacts of customer-generators on non-participating customers by comparing the bill reduction from solar to the cost to serve reduction from solar. (Tr. p. 165.10, ll. 1 – 14) Witness Harris stated that where the bill savings exceed the cost of service reduction, NEM customers are benefitting at the expense of non-NEM customers, and where the cost of service reductions exceed bill savings, non-NEM customers are benefitting from the installation of solar. *Id.* Harris further testified that embedded COSS "also reveal whether NEM customers would provide an adequate rate of return compared to the residential rate class if they were to be a separate class within a cost of service study." (Tr. p. 353.5, ll. 17 – 22)

DESC Witness Everett stated in rebuttal that "cost of service methodologies should be updated for 'costs related to use of the utility grid,' 'a customer's maximum use of the grid,' and whether the customer is serving load or exporting." (Tr. p. 131.16, ll. 12 – 16)

<u>Commission Conclusions</u>

The Commission finds that the novel customer-generator cost of service analysis will provide significant insight into the existing potential for cost shift between customer-generators and non-participants, but we do not find that its results will be, standing alone, determinative of a cost shift. The analytical exercise of separating customer-generators from others in their existing classes will provide the Commission additional information about the cost to serve customer-generators and about the adequacy of future revenue recovery from those customers. This tool is particularly helpful in the ratemaking context where the rates for customer-generators can be fine-tuned to come closer to parity with the overall class—in terms of relative rate of return—but it must be used in conjunction with the other tools in the Paragraph D toolkit in making an evaluation of the benefits and costs of a customer-generator program. With that caveat, the cost-of-service analytical tool is a critical piece of the Commission's current and future analysis of these programs, and an evaluation under the analytical framework cannot be conducted without this information in the record.

A COSS with a theoretical customer-generator class can inform, from a traditional ratemaking perspective, whether customer-generators are contributing sufficient revenue to prevent or avoid cross-subsidization within their rate class. As the record shows, even the narrow scope of a COSS may reveal that customer-generators are providing more benefit than costs to non-participating customers in their otherwise applicable rate class. The reduction in cost of service will manifest when a customer-generator class reduces its contribution to peaks or to the measure that costs are allocated. For example, DEC/DEP Witness Harris demonstrated that solar customers tend to reduce contributions to the coincident peak by approximately 75% compared to what those customers would contribute without having installed onsite solar. DESC apparently did not perform this required analysis, but Witness Furtick conceded that solar customers appear to have reduced their contribution to a peak day by over 40%. (Tr. p. 31, ll. 12 – 17) This type of "allocation benefit" currently accrues to the entire residential class because customer-generators within that class are helping reduce the class peak upon which transmission and generation costs are primarily allocated. This type of allocation benefit is not captured in the current avoided cost, wholesale value centered framework in Order 2015-194.

Accordingly, this information is very useful in understanding any possible intra-class subsidization and supplements the Commission's view of the overall program under the long-run valuation methodology, but it is not sufficient to be conclusive of a cost shift. To begin with, the cost of service framework is based on a single test year. In an embedded cost perspective, it fails to address future costs and benefits and only captures those values that materialize within the cost of service study within a single year. A marginal cost of service study will tell us more about the adequacy of rates and the ability of customer-generators to avoid costs in future years, but it too provides too narrow of a window to capture the full benefits that Act 62 requires the Commission to consider for both the existing NEM program and the future consideration of solar choice metering tariffs.

Lastly, this Act 62 analytical requirement does not suggest that the ultimate aim is to create a separate class of service for customer-generators. Instead, this theoretical exercise instead provides information regarding any potential intra-class cross subsidization that may or may not be occurring with customer-generators. The fair way to do this is to examine more closely whether customer-generators have a distinct cost to serve compared to other customers in the class and account for that difference in assessing whether rates are collecting adequate revenue from the theoretical class. While customer-generators may use the system in ways that other customers do not, as suggested by DESC Witness Everett, there is insufficient evidence in the record to support a conclusion that customer-generators exports of power cause any additional costs to the electrical utility in safely operating the grid. As discussed below, the Commission expects electrical utilities to take prudent measures to leverage these existing customer-generator facilities to provide beneficial ancillary services. It would be unjust and unreasonable to levy additional charges on customer-generators due to their electrical utility's inaction or unwillingness to utilize the potential benefits they bring to the local distribution system.

2. Embedded and marginal cost of service approaches

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 9

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DEC/DEP Witness Harris testified that the difference between marginal cost of service approaches and embedded ones is that a marginal cost analysis is "forward-looking" involving costs that have not yet been incurred while an embedded analysis looks at historical costs that have already been incurred. (Tr. p. 353.13, ll. 15 – 18) Witness Harris stated that "marginal and embedded costs for the same service may vary due to time dependent pricing fluctuations." *Id.* Witness Harris further recommended that "[a]s required by Act 62, the Commission should consider both embedded and marginal cost of service perspectives when evaluating any cost-shifts or subsidizations in rate designs. (Tr. p. 355.3, ll. 19 – 21)

ORS Witness Horii stated "[m]arginal costs are generally used when performing cost effectiveness studies or making resource decisions" while "embedded costs are generally used to determine the share of utility costs for which different customer classes should be responsible." (Tr. p. 576.14, ll. 6 – 8) Witness Horii testified that both embedded and marginal cost approaches are "valid and important" for the Solar Choice Metering Tariff design discussion. (Tr. p. 576.15, ll. 20 – 21) Witness Horii stated that the marginal-cost-based cost shift indicates the impact of a customer installing NEM solar at their premise and that this is the immediate impact without any rate changes and assumes the bill prior to NEM is the appropriate starting point. (Tr. p. 576.15, l. 20 – 576.16, l. 3) Horii stated that the embedded COSS does not assume that the bill before NEM is the correct starting point, but instead looks for its own starting point by modeling NEM solar customers as if they were a separate class or subclass. (Tr. p. 576.16, ll. 8 – 11)

In rebuttal testimony, DESC Witness Everett testified that she agreed with Witness Horii that "care must be taken to look at forward costs," but added that the marginal cost look should be technology agnostic. (Tr. p. 131.19, ll. 2 – 7) Witness Everett agreed with other witnesses that "both marginal and embedded cost methodologies are useful and provide a more complete picture in assessing future Solar Choice tariffs." (Tr. p. 131.19, ll. 11 – 13)

Joint Witness Beach, in his rebuttal testimony, stated that "Act 62 clearly expects that there is a balance between the embedded and marginal cost of service perspectives that needs to be achieved in the Solar Choice tariff." (Tr. p. 294.26, ll. 23 – 25)

Commission Conclusions

While Act 62 does not specify whether to require embedded or marginal cost of service studies, the Commission agrees with the majority of parties that there is benefit and unique information provided by both types of studies. Given the prevalence of solar PV and the emergence of energy storage within the Act 62 definition of customer-generator, the Commission finds that it is appropriate to consider specific technological characteristics that may impact marginal costs.

3. Data requirements for cost of service analysis

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NOS. 10 & 11

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DEC/DEP Witness Harris described the data used to perform the Act 62 embedded COSS. Witness Harris stated that two primary data sets are required: (1) cost of service studies and (2) production meter data from customer-generators. Witness Harris noted that DEC/DEP's cost of service studies are the same that currently effective rates are based on, from the rate cases in Docket Nos. 2018-318-E and 2018-319-E. (Tr. p. 353.6, ll. 4 – 16) Since the COSS utilized a 2017 test year, Witness Harris noted that production data meter from customer-generators in DEC was used to establish the solar profiles in the embedded COSS for that same 2017 test year. *Id.*

Witness Harris further stated that he applied two filters to production data. First, customers with less than nine months of interval data were excluded to ensure a more reliable annual analysis. Second, customers that generated less than 50% of their overall gross load (*i.e.*, the solar offset of customer onsite load) were excluded, because those customers tend to be, in Witness Harris's words, "not representative of the Companies' expectations for future NEM customers." Witness Harris stated that it is typical for NEM customers to install solar PV systems targeting an offset of at least 85% of gross load. As Witness Harris testified, this filter only resulted in a 6% decrease in customers in the analysis. (Tr. p. 353.7, ll. 4 – 14)

Witness Harris also detailed how DEC/DEP performed the cost of service study to model NEM customers as a theoretical separate class of service. After developing unit costs according to the 2018 COSS for customer costs, energy costs, distribution demand costs, transmission demand costs, and production demand costs, Witness Harris described how each unit cost was then multiplied by determinants to generate an estimated cost to serve for a representative customer both with and without rooftop solar. (Tr. p. 353.8, l. 2 – 353.10, l. 5) For an illustration of how the calculation is performed, Witness Harris stated:

> For example, to estimate energy costs, the energy unit cost would be multiplied by imports if the customer did not have solar generation. The same calculation would be done with the energy unit cost multiplied by the imports if the customer has solar generation. The estimated energy costs with and without solar can be compared to arrive at the total energy cost savings that are attributable to the addition of solar generation. This process was repeated for each unit cost to create a complete estimate for the costs the Companies incur for serving these customers with and without solar generation.

(Tr. p. 353.8, ll. 14 – 23)

Witness Harris described how the profiles for customers with and without solar generation were derived. He stated that production meter data was put through a "SAS model" to estimate the savings a customer would realize (*i.e.*, bill reductions) from installing solar. This resulted in a bill reduction number that could be compared to the reduction in cost to serve by applying the unit costs to determinants of customers with and without rooftop solar. (Tr. p. 353.9, ll. 14 – 19)

<u>Commission Conclusions</u>

Creating a theoretical customer class for customer-generators for purposes of the Act 62 analytical framework may require the collection of additional data that is not currently or readily available to electrical utilities. Where this is the case, the Commission requires that utilities begin to incorporate the analytical needs of Act 62 in designing load research studies that are ordinarily used to inform cost of service studies used in general rate cases. As advanced metering rollout continues, the Commission anticipates that hourly interval data (*i.e.*, 8760 load data) on the inflows and outflows from customer-generators will be available. For purposes of allocating costs, it is relevant to view the net hourly consumption of all customer-generators within a current class to develop a class load profile.

As discussed below, the Commission finds that electrical utilities should utilize the most recently used cost of service methodology upon which currently effective rates are based when performing this Act 62 cost of service theoretical class analysis. To perform this study, the utility shall look at the net load and demand that customer-generators within a class put on the grid. Because individual customer-generators can be net exporters in a given hour, it is reasonable to determine the theoretical class hourly net usage by taking the average of all consumption, including negative numbers associated with individual customer-generator net exports in that hour. Individual customer-generators engaged in NEM utilize exported kWhs to offset imported kWhs at a future time. It is reasonable to treat the unique characteristics of this theoretical customer class in the aggregate, so that a net export (negative load number) from Customer-Generator A at noon could be viewed as instantaneously offsetting Customer-Generator B in the same class with net imports (positive load number). This approach accounts for the diversity within the customer-generator class and treats the class as one aggregate net metered system account in terms of determining hourly net load.

The Commission finds that it is also informative to provide information on what the revenue impact on the actual class with customer-generators would have been if not for the customer-generator systems. For this analysis, it is necessary to estimate the counterfactual of what the theoretical customer-generators' gross load would have been without behind the meter generation. For this, electrical utilities would need to have, as DEC/DEP Witness Harris described, a separate meter to record hourly production from the customer-generators and then pair this with the customer-generators recorded metered net load (*i.e*., measured imports of exports) to determine what the gross load would have been in absence of the customer-generator. This additional counterfactual requirement will illustrate the differences in revenue requirement for all customers in a class with and without customer-generators. This is analytically distinct from the theoretical customer class analysis that looks at what revenue requirements would be if customer-generators were plucked out and placed in their own class. A counterfactual analysis will give a more complete picture as to what costs customer-generators have already saved the existing class by reducing the revenue requirement.

The Commission realizes that it could take electrical utilities some time to develop the data to produce these analyses with the same level of accuracy used in load research to support current cost of service studies. Therefore, the Commission finds it reasonable to allow electrical utilities in the interim to estimate customer-generator hourly generation profiles based on widely available tools utilizing a typical meteorological year, if actual solar generation profiles within the region and within the referenced time period (*i.e.*, test year) are not available. To estimate a customer-generator's gross load, it is reasonable to look at historic hourly usage data, where available, to reconstitute the customer's expected gross load for the counterfactual analysis described above. In some circumstances, it may be impossible for a utility to perform these analyses with imperfect or incomplete data. For such electrical utilities, the

Commission orders that a load research study capable of providing a statistically significant sample of customer-generators be initiated within sixty days of this order. The required cost of service analyses are critical to the Commission's consideration of the costs and benefits of any future solar choice metering tariff and rate design and are prerequisites to any determination of whether all future successor rate designs or tariffs are just and reasonable in light of the costs and benefits using the Act 62 analytical framework.

4. Cost of service methodology

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 12

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DEC/DEP Witness Harris stated that the Duke Companies thought it appropriate to utilize the cost of service studies and methodologies utilized in DEC and DEP Docket Nos. 2018-318-E and 2018-319-E, upon which existing rates are based. (Tr. p. 353.6, ll. 6 – 11)

ORS Witness Horii stated in his direct testimony that there are three steps to performing the Act 62 cost of service analysis that have decision points: (1) determine the otherwise applicable rate that will be used as the basis of comparison; (2) determine the test year to use for the embedded COSS; and (3) decide whether load and demand metrics should reflect historical or future conditions. (Tr. p. 576.12, l. 13 – 576.13, l. 13) ORS Witness Horii testified that he believes the 1 CP allocation method used in the Duke Companies' COSS in 2018 might have been appropriate two years ago, but that Duke is no longer solely summer peaking and that, by relying on this method, Duke is "underestimating the capacity costs that should be allocated to the NEM solar customers." (Tr. p. 576.19, ll. 1 – 13)

In rebuttal, Joint Witness Beach stated that Witness Horii, himself, acknowledged how it is important to have both an embedded and marginal evaluation of cost of service and that embedded COSS is important for "evaluating the policy issue of whether the solar customers would be paying their fair share of costs." (Tr. p. 576-16, ll. 16 – 18) Witness Beach stated that these costs are historic costs and that "therefore the allocators used to assign them to customer classes often will consider the demand drivers that caused them to be incurred in the past." (Tr. p. 294.26, ll. 9 – 12) Witness Beach concluded that "[f]rom this perspective, Duke's use of the Summer 1 CP allocator is reasonable, as Duke historically has been predominantly a summer-peaking utility, with the winter peaks emerging only in a few recent cold snaps." (Tr. p. 294.26, ll. 12 – 15) Witness Beach added that it is more appropriate to address any changes in cost of service methodology in a general rate case, "where a broad range of parties have significant interests in how the utility's costs are allocated to its customer classes." (Tr. p. 294.27, ll. 1 – 3)

Witness Harris responded to Witness Horii in rebuttal, stating that Witness Horii's citation to testimony from Glen Snider, a witness for the Duke Companies in the avoided cost docket, overlooked that Snider's testimony did not include or relate to an embedded cost study. (Tr. p. 355.6, ll. 14 – 17) Witness Harris stated that Witness Horii tends to accept that the methodology was approved in the Duke Companies' last rate case as "just and reasonable" and that it would be inappropriate to consider outside of a base rate case. (Tr. p. 355.6, ll. 8 – 13) Witness Harris further testified that he disagreed with ORS

Witness Horii that a marginal COSS is more appropriate than an embedded COSS, because it would be insufficient to satisfy the Commission's mandate to consider whether customer-generators are paying for their fair share of historical costs. (Tr. p. 355.8, ll. 12 – 19)

Commission Conclusions

The Commission finds that a utility's existing cost of service allocators, modified by the data inputs described in this Order, should be relied upon for purposes of this analytical framework. Cost of service allocations evolve and change from time to time, but it is most appropriate to consider any changes within the context of a general rate case proceeding where all parties affected by changes in allocation methods have sufficient notice and all other factors relating to the determination of the revenue requirement are before the Commission. Accordingly, the Commission rejects the suggestion by ORS Witness Horii that it is necessary and appropriate to abandon the cost of service approach used for currently effective rates of DEC and DEP for purposes of this analysis. The current rates have been determined to be just and reasonable based upon the allocation methodology contained in the existing approach, and this Order will not second guess that determination. The Commission invites ORS and all parties to present argument and evidence in a future general rate case as to whether a modification of cost of service allocators is justified.

C. Value of Distributed Energy Resources

1. Use of existing methodology approved by Order No. 2015-194

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NO. 13 & NO. 14

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DESC Witness Everett recommended only two changes to the calculation methodology (avoided energy component and line losses component) and did not recommend any additions or deletions to the categories of benefits. (Tr. p. 125.18) Witness Everett stated that the existing valuation methodology is consistent with other "value stack" methodologies, including the one used in New York state. *Id.* (ll. 3 – 8) Witness Everett produced a table populating the valuation categories, leaving five of the categories with a zero value. (Tr. 125.14)

ORS Witness Horii testified that assumptions of a zero avoided transmission and distribution capacity value for NEM should be revised and that a system-average non-zero value should be included in the marginal cost analysis used to inform any new NEM rates. (Tr. p. 576.17, l. 10 – 12)

Joint Witness Beach stated that all of the categories of benefits and costs have been quantified in other similar studies and that there are now well-accepted techniques available for populating those values. (Tr. p. 290.7, ll. 3 – 10) Witness Beach went on to provide that, if there is any uncertainty or doubt about a value, the default should not be to assign a zero value. Rather, Witness Beach stated that the "Commission should establish a reasonable value for the benefit or cost based on an examination of several cases that span a range of reasonable values for such a benefit or cost." *Id.*

Witness Everett, in rebuttal, testified that she did not update the categories where she assigned zero value based on her assertion that "[t]hese values have been thoroughly vetted via the regulatory process in South Carolina, and are the best representation of the value of the current NEM programs.” (Tr. p. 131.9, ll. 16 – 18)

In Witness Beach’s rebuttal testimony, he demonstrated and discussed methods to calculate non-zero values for many of the zero category values determined by DESC witness Everett. (Tr. p. 294.18, l. 7)

No other witness recommended the deletion or addition of any of the categories, despite various recommendations to change the calculation methodology for several of the existing valuation categories.

Commission Conclusions

There is no present controversy as to the continuing relevance and value of the valuation categories approved by Order 2015-194. Accordingly, the Commission finds that no changes to the value categories are justified at this time. The Commission notes, however, that there are varying levels of consensus and disagreement regarding the appropriate methods to analyze and quantify these value categories. As stated above, the Commission finds that a 25-year time horizon is appropriate for the Act 62 valuation methodology, to match the expected useful life of solar PV. Accordingly, the Commission modifies methodologies for calculating individual categories of value, as discussed below. The Commission expects these methods will continue to evolve over time.

Most importantly, the Commission adopts a standard of review in this Order that electrical utilities in utilizing the Order 2015-194 valuation methodology bear the burden of showing why a zero value is justified and why it is not practical or feasible to provide the analysis required. In most cases, whether a value exists or not is determined by whether an electrical utility is actively taking measures to leverage the characteristics of customer-generators to achieve those values. For example, this is most clearly illustrated within the categories of ancillary services and avoided distribution costs. If customer-generators are capable of providing additional benefits that are not being leveraged simply because of an electrical utilities' inaction, it raises questions of prudence regarding capital investments that proceed to serve the function that could potentially be served by distributed energy resources. The Commission requires electrical utilities to use best efforts and best practices to populate each category of value in the Order 2015-194 methodology, as modified here, in all future proceedings where this analytical framework is utilized.

Any failure of parties to adequately populate these values in past dockets, where little was at stake in terms of policy outcomes due to the Act 236 NEM Settlement, does not prejudice the Commission from requiring a far more robust effort in future proceedings. Act 62 requires the Commission to revisit methodology anew and to treat its administration and development on an iterative basis going forward. Accordingly, the Commission is not bound by any previous lack of rigor in calculating certain values in past dockets. All parties are now on notice that the Commission expects more robust showings on these categories moving forward.

The application of the Act 236 valuation methodology did not change the underlying policy options available to customer-generators. Rather, it affected only how electrical utilities recover DER program costs. To that extent, electrical utilities may have had a perverse incentive to suppress the valuation (or at least lacked an incentive to boost the valuation), as the lower the value, the higher the amount of the DER NEM Incentive that would be collected from customers. Whatever the relative importance of the methodology in the past, it certainly does have relevance to the future course of customer-generator policy and the Commission asks that all interested parties give it appropriate attention to provide a robust record for our consideration. The Commission will revisit these values on a regular basis.

The Commission further finds that, to the extent this Order amends the calculation methodologies for the existing cost-benefit categories approved by Order 2015-194, it is appropriate to require that utilities use these updated methodologies in determining the distributed energy component of their overall fuel factor in annual fuel proceedings under S.C. Code §58-27-865(A) for purposes of determining the NEM DER Incentive cost recovery associated with existing customer-generators. Further, because the energy industry's understanding and ability to quantify the costs and benefits of distributed energy resources is rapidly changing, the Commission finds that it is reasonable to keep this generic proceeding open and to reevaluate the NEM cost-benefit categories and their values on a biennial basis, with the next proceeding to convene two years after the issuance of this order.

2. Avoided energy

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NO. 15

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DESC Witness Everett's direct testimony recommended that the Commission modify the existing NEM Methodology to further segment avoided energy costs to represent variation in avoided energy cost by season and time of day. (Tr. 121, ll. 14 – 18). Witness Everett stated that "[f]urther delineating Avoided Energy Costs by season and time of use periods and then applying the actual energy produced during those same designated season and time of day periods would better represent the value of customer-generation." (Tr. p. 125.15, ll. 14 – 17)

In his direct testimony, Joint Witness Beach recommended that that the costs and benefits of distributed generation, including avoided energy costs, be extended to the 25 to 30-year useful life of a distributed generation system to comply with S.C. Code Ann. § 58-40-20(D)(1). (Tr. p. 290.14, ll. 14-17; p. 290.15 ll. 2-6) He recommended that avoided energy costs be extended to these longer terms by using fundamental forecasts of natural gas prices, the key driver of marginal energy costs. (Tr. p. 290.21, ll. 4 – 8). In his rebuttal testimony, Witness Beach responded to Witness Everett's direct testimony, noting that DESC appeared to use Dominion's 10-year levelized energy prices by time-of-use period as included in its standard offer Power Purchase Agreement tariff, and recommending that these avoided energy costs instead be extended to the 25-year economic life of a solar system. (Tr. p. 294.5, l. 24 – 294.6, l. 5) Witness Beach further testified that because gas-fired generation was expected to be the predominant marginal resource on the DESC system in the future, it was reasonable to expect marginal energy costs to increase over time. (Tr. p. 294.6, ll. 5 – 7) Using data from the Energy Information Administration's 2020 Annual Energy Outlook, Witness Beach calculated that the 25-year levelized price for the avoided energy benefits of solar PV represented a 21% increase over the 10-year levelized price, assuming an 8.5% discount rate corresponding to DESC's weighted average cost of capital. (Tr. p. 294.6, ll. 7-13).

Commission Conclusions

This Commission determines each electrical utility's avoided cost every two years in utility-specific avoided cost dockets. Thus, for purposes of utilizing the existing methodology for Act 236 purposes (*i.e.*, for establishing the annual amount of the DER NEM Incentive), the avoided energy costs determined in these proceedings has been sufficient. Under Act 62, however, the Commission now must account for statutory modifications to our oversight of Integrated Resource Plan and to the PURPA avoided cost methodology. Additionally, as discussed above, the Commission will evaluate the value of customer-generator DERs based on the expected useful life, determining the long-run marginal avoided costs over a 25-year horizon.

With these changes in statute, and in light of the task before us, the Commission modifies the requirement for calculation of avoided energy to include calculation of the seasonal and temporal (*e.g.*, on-peak period value) variations in avoided energy cost. Because the analytical framework is primarily examining the avoided cost value of solar PV, it is appropriate to determine a per kWh average price based on daylight hours where solar is expected to operate. The Commission also adopts the recommendation of Witness Beach to utilize fundamental forecasts of natural gas prices to extend the avoided cost over a 25-year time horizon to satisfy S.C. Code Ann. § 58-40-20(D)(1).

The use of a long-run forecast for avoided energy costs is appropriate for purposes of the Commission's evaluation of the costs and benefits of the current NEM program as well as any future solar choice metering tariff. This analytical exercise is distinct from the Commission's determination of wholesale rates for electrical utilities' purchases from qualifying facilities. While it is appropriate to utilize the PURPA avoided cost context as a starting point, the Commission's analysis of the costs and benefits of customer-generator programs is an exercise of Commission jurisdiction over retail practices under state law, not federal law.

3. Avoided capacity

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NO. 16

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

In his direct testimony, Joint Witness Beach recommended that that the costs and benefits of distributed generation, including avoided capacity costs, be extended to longer terms to comply with S.C. Code Ann. § 58-40-20(D)(1). (Tr. p. 290.14, ll. 14 – 17; p. 290.15, ll. 2 – 6) Witness Beach testified that these avoided capacity costs could be based on longer-term forecasts available in utility Integrated Resource Plans ("IRPs"), and that it was also important to allocate marginal capacity costs to time periods using long-term metrics for the set of hours when utility loads are likely to peak and generation capacity is most needed. (Tr. p. 290.21, ll. 9 – 13)

In his rebuttal testimony, Witness Beach critiqued DESC's stated avoided generation capacity costs for solar PV projects. In particular, Witness Beach estimated solar's capacity contribution by reviewing DESC's hourly loads from 2014 to 2019 and developing a Peak Capacity Allocation Factor ("PCAF") for each hour of the year, based on the extent to which hourly load exceeded 90% of the annual peak hour's load. (Tr. p. 294.8, ll. 15 – 20) Witness Beach then applied a solar profile to this PCAF distribution and determined that the solar PV capacity contribution was 34%, rather than the 11% solar capacity contribution adopted in Order No. 2019-847. (Tr. p. 294.9, ll. 4-7; p. 294.10, ll. 12 – 14) Witness Beach then calculated DESC's long-run avoided capacity costs based on the cost of a new combustion turbine ("CT") as the marginal source of capacity. (Tr. p. 294.9, ll. 9 – 11) Witness Beach used a cost of $918 per kW, as DESC provided in its 2020 IRP. (Tr. p. 294.10, ll. 4 – 5) Witness Beach's analysis resulted in an avoided generation capacity cost for a solar PV project of $0.01351 per kWh rather than the current Schedule PR-1 10 capacity credit of $0.00379 per kWh. (Tr. p. 294.10, ll. 5 – 10) Witness Beach further calculated that when the current credit was adjusted upward for his recommended 34% solar capacity contribution, the result would be a similar avoided cost capacity value of about $0.012 per kWh. (Tr. p. 294.10, ll. 11 – 15)

Commission Conclusions

The Commission modifies the existing valuation methodology to require that capacity costs be based on a 25-year forecast, conducted in a similar fashion as the forecast used for the IRP process. The Commission also adopts Witness Beach's recommendation that forecasts of capacity costs take into consideration the hours in which utility loads are likely to peak and when generation is most needed.

4. Ancillary services

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NO. 17

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DESC Witness Everett described ancillary services as a generation-related cost "related to maintaining system reliability and voltage control." (Tr. p. 125.6, ll. 1 – 2) Based on Order No. 2020-244 from DESC's 2019 avoided cost proceeding, Witness Everett assigned a zero value to ancillary services. (Tr. p. 125.14)

ORS Witness Horii noted in his testimony that ancillary services were assigned a zero value, stating that "some placeholder values may represent directly monetized costs or benefits (*e.g*., ancillary services) that may currently be small and/or difficult to quantify." (Hr'g Ex. 15 at 81) Witness Horii also provided that neither Maryland nor Montana quantified the value of ancillary services due to the "complexity of calculations and difficulty in deriving accurate results" and because ancillary services were "considered to be subjective and not quantifiable," respectively. (Hr'g Ex. 15 at 55)

Witness Beach did not attempt to quantify the value of ancillary services, but did note that all of the NEM methodology components could be quantified; he further testified that "[i]f there is uncertainty about the magnitude of a specific benefit or cost, the default should not be to assign a zero value to that category, but to examine several cases that span a range of reasonable values for this benefit or cost and use that review to establish a reasonable value." (Tr. p. 290.20, ll. 7 – 14) Alder Energy Witness Zimmerman agreed with Witness Beach's testimony on this issue, recommending that the Commission affirmatively value ancillary services to achieve an accurate value of customer-generated solar. (Tr. p. 494.7, ll. 14 – 17)

<u>Commission Conclusions</u>

The Commission finds that no change is required to the current methodology, as the record bears out that quantifying ancillary services is challenging and there are not current opportunities for customer-generators to provide such services. With the expectation that technology will continue to evolve rapidly and that customer utilization of battery storage will increase the types of services that customer-generators paired with storage can provide, the Commission requires the electrical utilities to investigate the feasibility of developing programs and capabilities to leverage ancillary service capabilities from customer-generators consistent with industry best practices (*e.g*., IEEE standards for DER and distributed generation). In the interim, it is reasonable to examine other jurisdictions for benchmark values for ancillary services provided by similarly situated customer-generators.

5. Avoided Carbon Dioxide Pollution

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NO. 18

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

Joint Witness Beach testified that the value of avoided carbon emissions, as included in the value stack of benefits adopted in Order No. 2015-194, should not be assigned a zero value. (Tr. p. 290.20, ll. 14 – 20) Witness Beach noted that while the future regulation and costs for mitigating carbon are uncertain, the IRPs of South Carolina utilities show that reducing future carbon emissions is a significant driver of those plans, and therefore that carbon compliance costs are not zero for ratepayers. *Id.* As with several other benefits in the value stack, Witness Beach testified that, where there is uncertainty about the magnitude of a specific benefit or cost, the default should not be to assign a zero value to that category, but to examine several cases spanning a range of reasonable values and using that review to establish a reasonable value. (Tr. p. 290.21, ll. 11 – 14)

On rebuttal, Witness Beach noted that DESC Witness Everett did not include a benefit associated with avoided costs to reduce greenhouse gas emissions, and argued that this value should not be assumed to be zero given that reducing future carbon emissions is a significant driver of South Carolina utility IRPs. (Tr. p. 294.17, ll. 13 – 20) Using the $25 per MT carbon cost assumption that DESC used in its 2020 IRP, along with a 2% inflation rate, Witness Beach calculated a benefit of $.01124 per kWh on a 25-year levelized basis. (Tr. p. 294.17, l. 21 – 294.18, l. 2)

Commission Conclusions

The Commission finds that it is reasonable to modify the existing valuation methodology to strike the requirement that "[a] zero monetary value will be used until state or federal laws or regulations result in an avoidable cost on Utility systems for these emissions." Currently, carbon dioxide (CO_2) costs are not included in the avoided energy component in this Commission's avoided cost determinations.

For purposes of this analytical framework, and under the exercise of the Commission's jurisdiction over retail practices, it is appropriate to consider a range of potential CO_2 values, as done in the IRP context. Act 62 specifically requires the Commission to consider a CO_2 price in the IRP evaluation. Moreover, a prudent utility will consider the risk of future regulation—gauging the current political and regulatory environment regarding likely legislation or regulation addressing climate change—in making its resource planning decisions. Therefore, it is reasonable to require a non-zero value for avoided CO_2 based on a 25-year forecast extension to the range of values used in the most recently approved IRP.

6. Avoided fuel hedge

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NO. 19

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

In his rebuttal testimony, Joint Witness Beach noted that DESC Witness Everett did not discuss or include a fuel hedge benefit in her testimony, and argued that such a benefit should be included. Witness Beach testified that because renewable generation reduces a utility's use of natural gas, it decreases the exposure of ratepayers to the volatility and periodic spikes in natural gas prices, which he stated had occurred regularly over the last several decades. (Tr. p. 294.15, ll. 6 – 10) Witness Beach testified that the value of the fuel hedge benefit should be calculated using a methodology used in the Maine Distributed Solar Valuation Study, a 2015 study commissioned by the Maine Public Utilities Commission and authored by Clean Power Research. This approach involves first calculating the cost of contracting for natural gas supplies today and setting aside the money needed to buy that gas in risk-free investments; then, the additional cost of this approach compared with the cost of purchasing gas on a "pay as you go" basis is the benefit of reducing the uncertainty in fuel costs that solar PV displaces. (Tr. p. 294.16, ll. 5 – 11) Witness Beach calculated this value for DESC and determined that the result is a value of $.033 per kWh as the 25-year levelized benefit of reducing fuel price uncertainty.

At the hearing, Witness Beach testified that he was unaware that the Commission had previously approved a zero value for DESC's fuel hedge value because the company did not operate a fuel-hedging program; however, Witness Beach specified that the fuel hedge value was significant because solar resources provide a fuel hedge for 25 years, much longer than typical utility hedging programs for their natural gas purchases. (Tr. p.

306, ll. 9 – 18) According to Witness Beach, renewable energy allows a utility to substitute upfront capital for the need to go out and purchase natural gas for the next 25 years, which significantly reduces ratepayer exposure to volatility and risk. (Tr. p. 307, ll. 4-22)

Alder Energy Witness Zimmerman agreed with Witness Beach's testimony on this issue, recommending that the Commission affirmatively value all methodology components, including fuel hedge, to achieve an accurate value of customer-generated solar. (Tr. p. 494.7, ll. 14 – 17)

Commission Conclusions

The Commission significantly modifies the existing valuation methodology to meaningfully incorporate fuel hedge value into the analytical framework, including consideration of the range of forecast values over the 25-year useful life horizon of solar PV systems. As with other categories, it is appropriate for the Commission to consider a range of potential future forecasts and values to account for the uncertainty of long-run estimates. The Commission recognizes that fuel hedging value may already be embedded in the PURPA standard avoided cost, but the Act 62 analytical framework adopted in this Order extends and considers the additional values that accrue for the full 25-year useful life of a solar PV system. Any 25-year fuel hedge value we adopt for purposes of analyzing a customer-generator program is not precedential nor necessarily applicable to the setting of a wholesale rate for QFs under PURPA. Under the Commission's jurisdiction over retail rates and practices, the Commission has the discretion to give appropriate weight to such forecasts in making its determination and is not confined to considering only the incremental administrative costs of electrical utility fuel hedging programs associated with the addition of customer-generators to the grid system.

7. Avoided transmission and distribution costs

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NOS. 20 & 21

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DESC Witness Everett defined distribution and transmission related costs as the "costs of building transmission and distribution capacity… and… cost related to line losses resulting from moving electricity across the system from generation to the customer." (Tr. p. 125.6, ll. 7 – 12) Witness Everett stated in rebuttal that she did not attempt to update the zero value for avoided T&D in her analysis in direct because "[t]hese values have been thoroughly vetted via the regulatory process in South Carolina, and are the best representation of the value of the current NEM programs. (Tr. p. 131.9, ll. 13 – 18)

Joint Witness Beach stated in direct testimony that "[a] fundamental attribute of DERs is that they are installed on the customer's premises, behind the meter and interconnected to the utility distribution system" and that "at today's penetrations of DERs, the predominant impact of DER generation is to reduce the peak demand for electricity that must be served from the transmission and distribution system." (Tr. p. 290.21, ll. 20 – 23) Witness Beach further testified that it is standard for utilities to value avoided transmission and distribution ("T&D") values for other similar demand-side programs, including DEC and DEP. (Tr. p. 290.14, l. 1) In terms of the method of calculating avoided T&D values, Witness Beach testified:

> There are longstanding and well-accepted methods to calculate long-run marginal costs for transmission and distribution capacity. Many utilities use the well-established National Economic Research Associates (NERA) regression method to determine their long-run marginal distribution capacity costs that vary with changes in load. The NERA regression model fits incremental transmission and distribution investment costs to peak load growth using at least 15 years of data to capture the utility's long-term marginal costs for capacity. The slope of the resulting regression line provides an estimate of the marginal cost of transmission or distribution investments associated with changes in peak demand. (Tr. p. 290.22, ll. 1 – 10)

Witness Beach, in rebuttal, discussed how he applied the NERA method and a Peak Capacity Allocation Factor—similar to that used to evaluate solar generation capacity contributions—to calculate a 25-year avoided transmission value for DESC of $0.01861/kWh and a 25-year avoided distribution value of $0.02270/kWh. (Tr. p. 294.12, l.12 – p.294.14, l. 21)

ORS Witness Horii testified that it is clearly possible to calculate distribution marginal capacity costs and that there are a "myriad" of jurisdictions that currently do so. (Tr. p. 576.24, ll. 9 – 13) Witness Horii cited a recent benchmarking study used in Colorado looks at a survey of avoided T&D costs for 20 states or regions. *Id.* Witness Horii stated that examples like this counter "the assertion that meaningful, aggregated distribution avoided costs cannot be calculated for DSM programs." (Tr. p. 576.27, ll. 1 – 7) Witness Horii provided that "assumptions of zero ($0) T&D capacity value for NEM solar should be revised and a system average non-zero value be included in the marginal costs analysis used to inform any new NEM rates." (Tr. p. 576.17, ll. 10 – 12)

For calculating avoided T&D values, Witness Horii testified that it would be ideal to estimate highly locational marginal distribution values for each smaller portion of the distribution system that has a capacity need in the near term. (Tr. p. 576.24, ll. 16 – 18) Short of this ideal situation—instead of assuming there is no avoided T&D value anywhere on the system—Witness Horii testified that "[i]t would be more appropriate to use a system average distribution capacity value than to exclude distribution capacity completely." (Tr. p. 576.25, ll. 1 – 3) Witness Horii stated that the approach to calculating avoided distribution also applies to calculating avoided transmission. (Tr. p. 576.27, ll. 8 – 16)

Witness Horii further explained how more precise avoided T&D values can be derived—such as in California where utilities produce a Grid Needs Assessment report and a Distribution Deferral Opportunity Report—but those approaches tend to have data that is not commonly available, including load forecasts for each distribution feeder and considerations of the amount of demand-side resources on a feeder. (Tr. p. 576.25, l.20 – 576.26, l. 17) Witness Horii explained that with this "kind of data of planned load growth related distribution investments and load forecasts with and without DSM, a calculation can be made for each feeder using the bottoms-up $/kW-year cost distribution investment required and avoided by DSM individually. *Id.* Even without such sophisticated procedures and granular data, Witness Horii stated that "distribution avoided costs are more commonly calculated using far less data, and both DESC and Duke have provided estimates of T&D marginal capacity costs" in response to Vote Solar data requests. *Id.*

<u>Commission Conclusions</u>

The Commission finds that avoided transmission and distribution costs are a non-zero value and electrical utilities should take greater effort to quantify a value using a methodology that accounts for relative availability of and granularity of data about the distribution and transmission system. While transmission and distributions costs are location specific, the Commission acknowledges that it would take a high degree of analytical sophistication and a more transparent T&D planning process to assign values with that level of precision and granularity in time and location. Accordingly, it is reasonable to provide electrical utilities flexibility at this time to employ a methodology that reflects the current state of available data. Specifically, the Commission finds that it is reasonable to derive the avoided T&D values from existing methods for evaluating demand-side management programs, according to the method described in Joint Witness Beach's rebuttal testimony which also figures in the long-run values according to a twenty-five-year expected life of solar PV.

Electrical utilities, however, are directed to provide the Commission, within 90 days of this order, a narrative of how they plan to improve these data capabilities over time to improve the visibility into the transmission and distribution systems and to modernize the planning of distribution and transmission assets to take into account the ability of DERs to avoid or defer traditional, utility-owned T&D capital investments.

8. Avoided line losses

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NO. 22

<u>Summary of the Evidence</u>

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DESC Witness Everett recommended modifying the avoided energy losses/line losses component of the NEM methodology. (Tr. p. 125.16, ll. 20 – 23) Specifically, Witness Everett testified that her recommendation was to first distinguish transmission and distribution losses, and then create a value for transmission losses that would apply to all customer-generation and a distribution losses component that applies to only the customer-generation simultaneously consumed on site. *Id*. According to Witness Everett, while kWhs consumed on site avoid both transmission and distribution losses, kWhs exported onto the system may not necessarily reduce the losses of energy delivered to other customer meters. (Tr. p. 125.17, ll. 1 – 9) She further testified that because exported kWh must be transported across the distribution system, the value of that kWh could also be eroded by distribution losses, thus becoming a negative value. (Tr. p. 125.17, ll. 6 – 9)

Joint Witness Beach's rebuttal testimony disagreed that power exported from distributed solar facilities does not avoid distribution line losses. (Tr. pp. 294.10 – 294.11) Witness Beach testified that "[a]ssuming that the penetration of distributed solar is low, as it is in South Carolina today, the power exported from a small customer-owned solar system on the distribution system will be consumed by the solar customer's immediate neighbors," (Tr. p. 294.11, ll. 1 – 4) and that "because the exports from distributed solar move such a short distance over the distribution system before they are consumed by the neighbors, the avoided line losses will not be significantly different that the avoided line losses from power consumed behind the meter." (Tr. p. 294.11, ll. 12 – 15) Witness Beach testified that a solar PV project located behind a customer's meter would avoid marginal line losses on both the DESC transmission and distribution system for its entire output, and calculated those total avoided losses to be $.00493/kWh on the DESC system. (Tr. p. 294.11, ll. 19 – 21)

DEC/DEP Witness Harris testified that Duke did not consider line losses in its analysis of how energy exports from NEM customers reduce system generation costs "because such losses are typically *de minimis*." (Tr. p. 353.9, ll. 2 – 3)

Commission Conclusions

The Commission modifies the existing methodology to require that electrical utilities determine the marginal line losses associated with customer-generator facilities. If marginal line loss data does not exist for an electrical utility, the Commission directs the development of a plan within 90-days of this order to acquire this capability for future proceedings.

The same marginal line loss factor shall be applied to both behind-the-meter consumption and to exports of electricity from the customer-generator to the grid. As provided by Witnesses Beach and Harris, the expectation of distribution losses for exports is *de minimis*, given the close proximity in which exported power will ordinarily be consumed by neighboring customers.

9. Utility integration, interconnection, and administrative costs

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NOS. 23 THROUGH 25

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

In direct testimony, DESC Witness Everett stated that "[i]nterconnection costs include those related to connecting a customer's facility or home to the grid not covered in specific Interconnection Fees. Integration costs are those related to maintaining voltage levels and load following given variability in the customer's loads and customer-generation resource production." (Tr. p. 125.6, ll. 14 – 18) Witness Everett further stated that "[a]dministrative costs include any additional costs the utility incurs to provide a NEM tariff, which may include the costs related to billing practices or incremental customer call center support." (Tr. p. 125.7, ll. 1 – 3) Witness Everett identified a zero value for administrative costs in her table of values. (Tr. p. 125.14, l. 1)

Commission Conclusions

While integration costs for solar generation are currently determined in avoided cost proceedings, the Commission finds here that it is inappropriate to apply this category to customer-generation that is completely consumed behind-the-meter. As discussed by Witnesses Beach and Harris, behind-the-meter consumption is equivalent to energy efficiency and any changes in load associated with offsetting purchases from the grid at any given time by any given customer will be smoothed by geographic and class diversity. (Tr. p. 38, l. 12 – 41, l. 15)

Moreover, the Commission now requires electrical utilities to begin to track incremental interconnection costs to ensure that the currently approved interconnection fee covers the reasonable costs of facilitating initial interconnection to the grid of customer-generator facilities. Similarly, if an electrical utility wishes to assign a value to administrative costs, it is necessary that the utility track and record incremental costs of administrating the NEM program that are distinguished from administrative costs that would have otherwise applied if the customer were not a customer-generator.

D. Economic Impacts of Net Energy Metering Program

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NOS. 26 & 27

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

SACE, CCL, Upstate Forever, and Vote Solar Witness Hefner testified that there are substantial economic impacts in South Carolina attributable to rooftop solar. (Tr. p. 415, l. 18 – 416, l. 8; p. 417.6, l. 14 – p. 417.7, l. 25) Witness Hefner explained that economic impact includes direct, indirect, and induced impacts. (Tr. p. 417.5, ll. 3 – 12) Direct benefits are the purchases of local goods, services, and labor. *Id.* Indirect impacts include wages paid to the installers of solar, and induced impacts include purchases of goods and services with those wages. *Id.* In the context of the rooftop solar sector of the solar industry, direct impacts include wages paid to the installers of solar panels, indirect impacts include the purchase of goods and services by businesses that install solar panels in South Carolina, and induced impacts are the impact of purchases as a result of wages paid to those businesses. *Id.*

Witness Hefner explained that his study used direct impact values, namely job numbers, into a regional economic model to determine the total economic benefit of the jobs created by the solar industry in South Carolina. (Tr. p. 417.5, ll. 18 – 22) Witness Hefner further explained that he derived the economic benefit of the jobs created by the residential solar subset of the solar industry in the state and that these benefits were significant. (Tr. p. 417.7, ll. 5 – 9) Witness Hefner noted that environmental benefits and cost savings for solar customers were not factored into the economic benefits calculated by his study. (Tr. p. 417.4, ll. 13 – 15; p. 435, l. 22 – 435, l. 19)

DESC Witness Furtick objected to the Commission considering the economic benefits associated with induced impacts, arguing that these impacts are “almost impossible to accurately quantify.” (Tr. p. 25.2, ll. 9 – 11) Witness Furtick conceded that the number of solar jobs created in South Carolina and the wages paid to workers employed in those jobs are measures of economic impact on the State’s economy. (Tr. p. 50, ll. 11 – 25)

ORS Witness Horii acknowledged that residential solar generation provides myriad social and market benefits including CO2 value, healthcare and mortality impacts from criteria pollutant reductions, market price impacts, and increased jobs. (Tr. p. 576.5, ll. 16 – 19)

<u>Commission Conclusions</u>

The Commission concludes that it is standard practice for economic impact models that quantify the direct, indirect, and induced impacts of an industry to be used to calculate economic benefits to state or regional economies and help inform policymaking decisions. The Commission finds that no witness or party other that witness Hefner provided evidence regarding the economic benefits of the rooftop solar industry in South Carolina. The Commission accepts Witness Hefner’s characterization of direct, indirect, and induced economic impacts. For the purposes of Act 62, which requires the Commission to consider both direct and direct economic impacts of the NEM program, it is appropriate to include payment for service, labor, and goods businesses in the residential solar sector; purchases of goods and services in South Carolina by those businesses; and the purchases made possible by wages paid to workers in the residential solar sector.

1. Use of economic impact information in analytical framework

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NOS. 28 THROUGH 30

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

SACE, CCL, Upstate Forever, and Vote Solar Witness Hefner testified that the Commission should consider his analysis of the economic impact of the solar industry and rooftop net-metered solar in particular when evaluating the costs and benefits of the NEM program. (Tr. p. 417.4, ll. 16 – 21) DESC Witness Furtick testified that Witness Hefner's analysis should not be relied upon for actually establishing rates because it includes induced impacts analysis. *Id.*

Commission Conclusions

The Commission concludes that it is required by Act 62 to consider the direct and indirect economic impacts of the net metering program on the State. However, Act 62 does not direct the Commission to extrapolate the value of distributed energy resources or NEM customer rates from an economic impact study. Instead, the Commission shall qualitatively weigh the direct and indirect economic benefits of the net metering program when setting just and reasonable rates and evaluating the NEM program and successor tariffs. In sum, Witness Hefner's study quantifying the economic benefits created by the residential subset of the solar industry in South Carolina shall inform the Commission's consideration of the NEM program and successor tariffs.

2. Jobs data and other data source issues

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NO. 31

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

SACE, CCL, Upstate Forever, and Vote Solar Witness Hefner testified that his analysis of the economic impact of the solar industry in South Carolina used job numbers as inputs into a regional economic input model. Witness Hefner explained that the job numbers came from the Solar Foundation's annual census of solar jobs for the years 2018 and 2019. (Tr. p. 417.5, ll. 20 – 22) Witness Hefner acknowledged that he did not independently verify the jobs data produced by the Solar Foundation. (Tr. p. 439, ll. 19 – 22)

DEC/DEP Witness Wright critiqued Witness Hefner's reliance upon jobs data generated by the solar industry, asserting that the Solar Foundation's census was likely biased. (Tr. p. 262.11, ll. 12 – 16) However, Witness Hefner explained that it was typical for economists quantifying the economic impacts of an industry to rely on surveys conducted by the industry in question. (Tr. p. 437, ll. 4 – 15) Witness Wright also asserted that some of the solar jobs that the Solar Foundation census identified as being located in South Carolina could have been double counted in North Carolina. Witness Wright conceded that he had no evidence confirming this assertion. (Tr. p. 262.12, ll. 1 – 13) Witness Wright also acknowledged that Duke Energy did not attempt to verify the number of solar jobs in South Carolina. (Tr. p. 269, l. 25 – 270, l. 2)

Alder Energy Witness Zimmerman testified that he had received and filled out the Solar Foundation's annual survey in the past. (Tr. p. 504, l. 19 – 505, l. 20) Witness Zimmerman further testified that he had filled out and returned the survey at least once since 2018, but that he, and likely other companies in the solar industry, had failed to return the survey on occasion, suggesting that the number of solar industry jobs may be greater than reflected by the survey. *Id.*

DESC Witness Furtick conceded that DESC did not make any effort to quantify the jobs created by rooftop solar industry in their territory or to quantify the impact that those jobs have on the State's economy. (Tr. p. 51, ll. 1 – 11)

Commission Conclusions

The Commission concludes that it is reasonable to rely on the Solar Foundation's job census to estimate solar jobs in South Carolina and analyze the economic benefits derived from those jobs. The Commission agrees with Witness Hefner that it is reasonable to rely on an industry's self-reported job numbers, particularly when no other parties have proposed alternative figures or demonstrated that the industry's self-reported job numbers are inaccurate.

3. Use of economic impact modelling

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NO. 32

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

SACE, CCL, Upstate Forever, and Vote Solar Witness Hefner testified that his analysis relied on a regional impact model, IMPLAN, to assess the total economic impacts of jobs created by the solar industry in South Carolina. (Tr. p. 417.5, ll. 20 – 22) Witness Hefner explained that IMPLAN—or Impact Analysis for Planning—is a model commonly used to measure economic impacts. Witness Hefner testified that many researchers, federal, state, and local governments, universities, and private companies, rely on this model. Witness Hefner also testified that Duke Energy had recently used

IMPLAN to calculate the economic benefits of its Grid Improvement Plan for North and South Carolina. (Tr. p. 417.6, ll. 1 – 9) Witness Hefner explained that IMPLAN localizes the impacts of spending to a study area, in this case, the state of South Carolina, and ensures that spending that leaves the state is not considered in the study. (Tr. p. 417.6, ll. 9 – 12)

DEC/DEP Witness Wright acknowledged that Duke Energy has employed IMPLAN to analyze economic benefits. (Tr. p. 265, l. 24 – 266, l. 2) Witness Wright testified that using IMPLAN to calculate net benefits rather than gross benefits of an industry would factor in the opportunity cost of investing in solar and asserted that this use of IMPLAN could potentially conclude that the costs exceed the benefits. (Tr. p. 278 ll. 4-13)

Witness Hefner explained that including the opportunity cost in the IMPLAN analysis was impossible unless the researcher has a list of alternative ways in which the money being invested in solar could be spent. (Tr. p. 433, ll. 2 – 13) Witness Hefner acknowledged that his study does not account for opportunity cost associated with an investment in solar, but explained that this was standard practice, and that entities including Duke Energy and Volvo do not include opportunity cost in their economic impact studies either. (Tr. p. 425, l. 24 – 426, l. 4; p. 432, l. 5 – 433, l. 17) Witness Hefner further explained that in his experience as an expert in the field of regional economics, these opportunity costs are not typically included in economic impact studies. (Tr. p. 432, l. 5 – 433 1. 17)

Commission Conclusions

The Commission concludes IMPLAN acceptable for purposes of determining the economic impact of NEM and any successor tariff on South Carolina. No Parties have taken issue with the use of the IMPLAN tool itself. The Commission does not address whether a net or gross economic impact analysis is more appropriate for evaluating the economic impacts.

4. Audubon Study

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACTS NOS. 33 & 34

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

SACE, CCL, Upstate Forever, and Vote Solar Witness Hefner testified that his study calculated significant economic benefits generated by the solar industry in South Carolina. For the year 2018, IMPLAN calculated the total economic impact of the solar industry as $1,169,009,854. (Tr. p. 417.6, l. 18 – 417.7, l. 2) For the year 2019, IMPLAN calculated the total economic impact of the solar industry at $1,538,920,852. According to this calculation, the solar industry in South Carolina supported 6,330 jobs in 2018 and 7,250 jobs in 2019.

Witness Hefner also testified as to his calculations of the economic impact of the solar industry by market segment. (Tr. p. 417.7, ll. 5 – 14) Witness Hefner calculated that the residential segment of the solar industry had a total economic impact of $655,814,528 in 2018 and $863,334,598 in 2019. According to this calculation, the residential segment of the South Carolina solar industry supported 3,551 jobs in 2018 and 4,067 jobs in 2019.

Commission Conclusions

The Commission concludes that Witness Hefner's study represents a reasonable estimate of the economic impact of the solar industry in South Carolina. The Commission further concludes that it is reasonable and appropriate to consider the economic impacts of the solar industry, and especially residential rooftop solar, as calculated in Witness Hefner's economic impact study, when evaluating the value of NEM and solar choice tariffs.

As previously noted, the Commission will not rely directly on economic impact studies to derive the value of distributed energy resources or net metering customer rates from an economic impact study. Instead, the Commission shall qualitatively weigh the direct and indirect economic benefits of the net metering program when setting just and reasonable rates and evaluating the NEM program and successor tariffs.

Witness Hefner's analysis demonstrates the magnitude of economic growth generated by residential solar and the net metering program in this state. In light of these significant economic benefits, the NEM program has satisfied its intended purpose of kick starting the solar market and giving customers more options.

E. Cost-Effectiveness Tests

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 35 THROUGH 39

<u>Summary of the Evidence</u>

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DESC Witness Everett conducted a cost-benefit analysis of DESC's current NEM offerings using cost-benefit tests included in the California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects (standard practice manual), tests which are commonly used to evaluate customer energy efficiency and demand-side management programs. (Tr. p. 125.21, ll. 11 – 14) Witness Everett testified that energy efficiency and demand-side management programs have similar characteristics to NEM programs, and that California recently used these tests in a NEM successor tariff proceeding. (Tr. p. 125.23, l. 9 – 125.23, l. 3)

Witness Everett conducted a cost-benefit analysis for DESC's NEM programs using four of the tests from the manual: the Total Resource Cost Test ("TRC"), the Program Administrator Cost Test ("PAC"), the Participant Cost Test ("PCT"), and the Ratepayer Impact Measure Test ("RIM"). (Tr. pp. 125.23-125.24) Each of these tests measures the cost-effectiveness of a program from a different perspective. The TRC test measures the net benefits or costs of the customer generation resource option, including costs and benefits to both the utility and the customer. (Tr. p. 125.24) The PAC test (also known as the Utility Cost Test, or UCT) measures cost-effectiveness from the program administrator's perspective. (Tr. p. 125.25, ll. 2 – 8) The PCT measures the benefits and costs to a participating customer, and the RIM test measures whether customer rates will increase or decrease due to a program. (Tr. p. 125.25, l. 10 – 125.26, l. 5)

DESC conducted these cost-benefit analyses for its Residential Single Family and Small Commercial customer sectors. Using the NEM Methodology values and the results of the solar forecast presented by DESC Witness Robinson, Witness Everett generated a 10-year levelized value for each value component over a 20-year evaluation period.

Witness Everett testified that under the PCT, DESC's NEM programs showed net benefits to participating customers of 11.7 and 7.3 cents per kWh for the Residential and Small Commercial sectors, respectively. (Tr. p. 125.34) Under the PAC test, both sectors had net benefits of zero because the utility is made whole through current cost recovery mechanisms. *Id.* Under DESC's analysis, the NEM programs showed negative net benefits under the RIM and TRC tests. *Id.*

Joint Witness Beach's direct testimony stated that Act 62 requires the Commission to balance the interests of all ratepayers, both participants (ratepayers who install DERs) and non-participants (customers who do not adopt DERs and who will pay rates that may include costs associated with DER adoption). (Tr. p. 290.16, ll. 15 – 18) Witness Beach recommended that for participants, the Commission use the PCT to gauge whether the adopted solar choice tariff results in a reasonable and economic opportunity for customers to continue to adopt DERs. (Tr. p. 290.16, ll. 18 – 21) For impacts to non-participants, Witness Beach recommended that the Commission evaluate NEM programs using the UCT. (Tr. p. 290.16, ll. 21-22) Witness Beach noted that the UCT "measures whether any additional costs that result from DER adoption and that the utility must recover in rates from all ratepayers (including from non-participants) are offset by the direct benefits of DERs." (Tr. p. 290.16 l. 22 – 290.17, l. 1) Witness Beach strongly recommended against the Commission's use of the RIM test to evaluate impacts to non-participants. First, he testified that it penalizes DER customers for their behind-the-meter usage because the test calculates the revenues the utility might have earned but for that customer's NEM generation, and allocates those lost revenues to DER customers. Witness Beach further noted that the RIM test is entirely backward-looking and does not look at the incremental costs resulting from new customers signing up for a NEM program. Finally, Witness Beach testified that the use of the RIM test is inappropriate because it does not evaluate whether a DER is a cost-effective resource for the utility system such that it would result in overall savings to all ratepayers. Witness Beach noted that any potential inequity revealed by the RIM test could be addressed by ensuring that all ratepayers have reasonable access to DERs or similar programs. (Tr. p. 290.19, ll. 12 – 14)

In his rebuttal testimony, Witness Beach responded to the cost-benefit analyses in DESC Witness Everett's direct testimony. Witness Beach testified that the benefits and costs of distributed resources should be examined from multiple perspectives and recommended that the Commission consider the results of all standard practice manual tests for cost-effectiveness except for the RIM test. (Tr. p. 294.23, ll. 22-30) According to Witness Beach, when using his recommended 25-year levelized annual calculations of solar PV's costs and benefits, rather than the 10-year levelized values used by DESC, distributed solar on DESC's system passes all five of the standard practice manual tests. (Tr. p. 294.24 ll. 4 – 5) Thus, Witness Beach concluded that solar DG is a cost-effective resource for DESC, that it does not cause a cost shift to non-participating ratepayers (as shown by the RIM and UCT results), and that modifications to net metering are not needed to recover DESC's full cost of service over time from NEM customers. (Tr. p. 294.25, ll. 1 – 12)

Commission Conclusions

The Commission finds that Act 62 requires the Commission to balance the interests of all ratepayers, including customer-generator participants in NEM and non-participants, and that the use of the standard practice manual cost-effectiveness tests are reasonable to consider in evaluating the costs and benefits of NEM programs.

Specifically, the Commission concludes that the Participant Cost Test is appropriate to consider whether the customer-generator program, including any associated incentives, provides a reasonable economic opportunity for customers to invest in and use distributed energy resources under a specific program, such as NEM or a future solar choice metering tariff. The Commission further concludes that the Utility Cost Test is appropriate to determine whether any additional costs that result from customer-generator adoption of solar PV or distributed energy resources are offset by the direct benefits of the customer-generator program.

The Commission agrees with Witness Beach that the use of the RIM test is inconsistent with the Act 62 Framework. The RIM test inappropriately penalizes behind the meter consumption of onsite generation and takes a backward-looking view of utility costs that re-allocates sunk costs to customer-generators instead of considering incremental costs resulting from new customer-generators signing up under a particular program.

VI. ADDITIONAL ISSUES

A. Use of the Analytical Framework in Concurrent Solar Choice Metering Proceedings

The Commission recognizes the timing of a final order on the analytical framework makes it unlikely that the solar choice metering tariff filings—which were filed months before this order—will perfectly conform to these requirements. The statute enumerates several mandatory categories of consideration, so it is important that the Commission receive and consider evidence supporting those mandatory analyses, even if the contents and methodological assumptions do not precisely match the range of assumptions deemed reasonable within the analytical framework. Parties are on notice of what the statute expects and requires, at least on this categorical level.

Even without advance guidance of specific methodological changes to existing valuation methods, the Commission expects utilities to provide the information required by statute. An electrical utility seeking approval of a solar choice metering tariff bears the burden of showing that it complies with the law and otherwise is just and reasonable. In this context, carrying that burden includes ensuring that the evidentiary record includes sufficient information and analyses to meet the mandate of Act 62 that the Commission "shall consider" four distinct categories of information, setting aside subsection (5) catchall category for information the Commission deems relevant.

The analytical framework allows for considerable variation in methodology in this first run of solar choice metering tariffs given the likely differences in availability of relevant data across the three utilities. The Commission takes an eye toward the information presented in the solar choice dockets as a preliminary iteration and will consider waivers of certain requirements on a temporary basis, should the utility make a persuasive case for why strict compliance is not possible and that a reasonable accommodation has been made to satisfy the evidentiary needs under the statute.

B. Commission Authority to Order Further Proceedings to Cure Evidentiary Deficiencies and to Establish Interim Solar Choice Metering Tariffs as Necessary

It is the Commission's intent that flexibility with the application of the analytical framework to the currently pending solar choice metering tariff proceedings will accommodate a durable outcome and avoid the need for approving an interim, conditional successor tariff to NEM. However, if the Commission is not satisfied that the respective record before us allows us to perform our duty under Act 62, the Commission will use its discretion to order further proceedings to adopt interim measures that retain meaningful opportunities for customer-generators to achieve significant bill savings as a result of installing on-site solar PV. It would be error to confuse the flexibility the Commission is willing to extend in regard to this first run of the analytical framework in the ongoing solar choice dockets with a waiver of the burden of proof applicable to an electrical utility (or other party) seeking adoption of a specific rate proposal or change in practice. The Commission will not significantly change existing customer-generator programs without sufficient evidence—a safeguard the General Assembly included in Act 62—that more significant changes are warranted to achieve a balance of the goals of Act 62 solar choice metering.

Should the Commission determine that an evidentiary record of a solar choice metering tariff docket is incomplete or insufficient because of a gross departure from the analytical framework and the requirements of Act 62, the Commission retains authority to approve interim measures to comply with the date certain establishment of a solar choice metering tariff and the General Assembly's intent to "avoid disruption to the growing market for customer-scale distributed energy resources…." S.C. Code Ann. § 58-40-20(A)(2). To be clear, the Commission is bound by law to approve a successor "'solar choice metering tariff' for customer-generators to go into effect for applications received after May 31, 2021." S.C. Code Ann. § 58-40-20(F)(1). It is the Commission's determination that it may be reasonable to adopt an interim policy that minimizes the degree of disruption and change to customer-generator policy while we cure any evidentiary deficiencies. The law requires the Commission to balance a thriving South Carolina solar market with the desire to "eliminate any cost shift to the greatest extent practicable on customers who do not have customer-sited generation…." S.C. Code Ann. § 58-40-20(A)(1) and (G)(1). For example, the Commission has both inherent authority under our exclusive jurisdiction over retail practices and explicit authority under Act 62, to modify the "netting interval" (i.e., the "energy measurement interval") in a manner that is just and reasonable in light of the record before us. S.C. Code Ann. § 58-40-20(F)(3).

VII. ORDERING PARAGRAPHS

1. The Commission requires that utilities begin to incorporate the analytical needs of Act 62 in designing load research studies ordinarily used to inform cost of service studies and to initiate a load research study that includes a statistically significant sample of customer-generators within sixty (60) days of this Order.

2. The Commission requires electrical utilities to investigate the feasibility of developing programs and any technological capabilities that would be necessary to leverage ancillary service capabilities from customer-generators. The electrical utilities shall file a plan for initiating this investigation within ninety (90) days of this Order and submit a report in this docket within one year of this Order.

3. Electrical utilities are directed to provide the Commission, within ninety (90) days of this order, a narrative of how the utility plans to improve its data capabilities and to modernize the planning of distribution and transmission systems to take into account the ability of DERs to avoid or defer traditional utility owned transmission and distribution investments and to otherwise reduce operational costs of those systems.

4. Within ninety (90) days of this Order, the Commission requires electrical utilities to file a statement of its current capabilities to measure marginal line losses associated with customer-generator facilities or to file a plan of how that measurement capability will be achieved in future valuation proceedings.

5. The Commission requires electrical utilities to begin tracking the incremental costs of interconnecting customer-generators to the electric grid to ensure

that currently approved interconnection fees cover the reasonable costs of facilitating such interconnection.

6. To the extent the existing DER valuation methodology adopted by Order 2015-294 is modified by this Order, the Commission directs utilities to use these updated methodologies in determining the distributed energy component of their overall fuel factor in annual fuel proceedings under S.C. Code §58-27-865(A) for purposes of determining the NEM DER Incentive cost recovery associated with existing customer-generators.

January 21, 2021

/s/ Katherine L. Mixson
Katherine L. Mixson
SC Bar No. 104478
Southern Environmental Law Center
525 East Bay St, Suite 200
Charleston SC 29403
(843) 720-5270
klee@selcsc.org

Counsel for South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Upstate Forever

/s/ Thadeus Culley
Thadeus Culley
SC Bar No. 104428
1911 Ephesus Church Road
Chapel Hill, NC 27517
(504) 616-0181
thad@votesolar.org

Counsel for Vote Solar

/s/ Peter Ledford
Peter Ledford (admitted pro hac vice)
NC Bar No. 42999
4800 Six Forks Road, Suite 300
Raleigh, NC 27609
(919) 832-7601 ext. 107
peter@energync.org

Counsel for North Carolina Sustainable Energy Association

/s/ Jeffrey Kuykendall
Jeffrey Kuykendall
SC Bar No. 102538
127 King Street, Suite 208
Charleston, SC 29401
(843) 790-5182
jwkuykendall@jwklegal.com

Counsel for Solar Energy Industries Association and North Carolina Sustainable Energy Association

CERTIFICATE OF SERVICE

I hereby certify that the parties listed below have been served with a copy of the *Joint Proposed Order* filed on behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Upstate Forever, Vote Solar, NCSEA, and SEIA by electronic mail.

Adam Protheroe, Counsel
S.C. Appleseed Legal Justice Center
Post Office Box 7187
Columbia, SC 29202
adam@scjustice.org

Carri Grube Lybarker, Counsel
South Carolina Department of Consumer Affairs
clybarker@scconsumer.gov

R. Taylor Speer, Counsel
Turner, Padget, Graham & Laney, P.A.
Post Office Box 1509
Greenville SC 29602
tspeer@turnerpadget.com

Jenny R. Pittman, Counsel
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
jpittman@ors.sc.gov

K. Chad Burgess, Director & Deputy General Counsel
Dominion Energy Southeast Services, Incorporated
220 Operation Way - MC C222
Cayce, SC 29033
chad.burgess@dominionenergy.com

Bess J. DuRant, Counsel
Sowell & DuRant, LLC
1325 Park Street, Suite 100
Columbia, SC 29201
bdurant@sowelldurant.com

Heather Shirley Smith, Deputy General Counsel
Duke Energy Carolinas/ Duke Energy Progress, LLC
40 W. Broad Street, Suite 690
Greenville, SC 29601
heather.smith@duke-energy.com

J. Ashley Cooper, Counsel
Parker Poe Adams & Bernstein, LLP
200 Meeting Street, Suite 301
Charleston, SC 29401
ashleycooper@parkerpoe.com

Marion William Middleton III, Counsel
Parker Poe Adams & Bernstein, LLP
110 East Court Street
Suite 200
Greenville, SC 29601
willmiddleton@parkerpoe.com

Jeffrey M. Nelson, Counsel
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
jnelson@ors.sc.gov

Matthew W. Gissendanner, Senior Counsel
Dominion Energy South Carolina, Incorporated
220 Operation Way - MC C222
Cayce, SC 29033-3701
matthew.gissendanner@dominionenergy.com

Peter H. Ledford, General Counsel and Director of Policy
North Carolina Sustainable Energy Association
4800 Six Forks Road, Suite 300
Raleigh, NC 27609
peter@energync.org

Jeffrey W. Kuykendall, Counsel
Attorney At Law
127 King Street, Suite 208
Charleston, SC 29401
jwkuykendall@jwklegal.com

Rebecca J. Dulin, Counsel
Duke Energy Carolinas/Duke Energy Progress, LLC
1201 Main Street, Suite 1180
Columbia, SC 29201
Rebecca.Dulin@duke-energy.com

Robert R. Smith, II, Counsel
Moore & Van Allen, PLLC
100 North Tryon Street, Suite 4700
Charlotte, NC 28202
robsmith@mvalaw.com

Roger P. Hall, Assistant Consumer Advocate
South Carolina Department of Consumer Affairs
Post Office Box 5757
Columbia, SC 29250
rhall@scconsumer.gov

Thadeus B. Culley, Regional Director and Regulatory Counsel
Vote Solar
1911 Ephesus Church Road
Chapel Hill, NC 27517
thad@votesolar.org

This the 21st day of January, 2021.

/s/ Katherine L. Mixson